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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE

+ + + + +

WEDNESDAY

OCTOBER 1, 2014

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., Gordon R. Skillman, Chairman, presiding.

COMMITTEE MEMBERS:

GORDON R. SKILLMAN, Subcommittee Chairman

RONALD G. BALLINGER, Member

DENNIS C. BLEY, Member

CHARLES H. BROWN, JR., Member

MICHAEL L. CORRADINI, Member

DANA A. POWERS, Member

HAROLD B. RAY, Member

JOY L. REMPE, Member

PETER RICCARDELLA, Member

MICHAEL T. RYAN, Member

STEPHEN P. SCHULTZ, Member

JOHN W. STETKAR, Member

DESIGNATED FEDERAL OFFICIAL:

MARK L. BANKS

ALSO PRESENT:

JOHN BRANDEAU, Fort Calhoun

LOUIS CORTOPASSI, OPPD

JODY FARHAT, USACE

JOE GASPER, OPPD

MIKE HAY, RIV

LOUISE LUND, NRR

TONY VEGEL, RIV

*Present via telephone

T-A-B-L-E O-F C-O-N-T-E-N-T-S

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

(8:30 a.m.)

CHAIRMAN SKILLMAN: Good morning. The meeting will now come to order. This is a meeting of the Advisory Committee and Reactor Safeguards Plant Operations and Fire Protection Subcommittee. I'm Gordon Skillman, chairman of the subcommittee. ACRS members in attendance are Pete Riccardella, Steve Schultz, Dana Powers, Harold Ray, John Stetkar, chairman of the ACRS, Dennis Bley, Ron Ballinger, Joy Rempe and Mike Corradini. The designated federal official is Mark Banks.

The purpose of today's meeting is for the NRC staff and Fort Calhoun Station personnel to discuss the implementation of the increased regulatory oversight at Fort Calhoun using the Inspection Manual Chapter 0350 process. In addition, we're pleased to have a representative from the U.S. Army Corps of Engineers that will provide an overview of the Corps' management of the Missouri River Basin.

The subcommittee will gather information, analyze relevant issues and facts, and formulate a proposed position and action as appropriate for deliberation by the full committee, if needed. The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the Federal Register on September 25th, 2014.

The meeting will be open to public attendance, with the exception of portions that may be closed to protect information that is proprietary, pursuant to 5 U.S.C. 552b(c)(4). We have received no written comments or requests for time to make oral statements. A transcript of today's meeting is being kept and will be made available as stated in the Federal Register Notice. Therefore, we request that meeting participants please use the microphones located throughout the meeting room when addressing the subcommittee.

Participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. A telephone bridge line has been established for this meeting. To preclude interruption of the meeting, please mute your individual phones and lines during presentations and subcommittee discussion. I ask that you silence your cell phones, please.

Late last summer, 2013, Mark Banks and I began the preparation of the significant operating experience presentation that was scheduled for last October. That meeting was conducted on March 7th of 2014. You might remember some of the facets of that meeting regarding the revised oversight process and the color coding for the various issues as they were identified relative to differential core damage frequency and differential LERF.

If you may remember, flooding was the topic that was prominent in our minds then, and we had done reviews on ocean located plants and riverine plants, and we were considering issues considering tsunami and subsequent dam failures.

At that time, Mark and I began preparation for this meeting so this meeting has been in preparation for a year. Our vision then was to attempt to include colleagues from the Fort Calhoun Station, from the NRC staff and from the Army Corps of Engineers to focus on Calhoun's challenges before, during and after the 2011 Missouri River flooding.

We believed then and still do that this experience has the capacity to inform the ACRS and help us in our deliberations regarding nuclear plant safety.

So the meeting's been a year in the making, and I thank the Army Corps of Engineers, the NRC staff and the Fort Calhoun staff for their preparation and for their presentation in this meeting. Thank you very much.

We will now proceed with the meeting, and I call on Mr. Tony Vegel, director of Region IV's Division of Reactor Safety and chair of the Fort Calhoun 0350 Panel, and Ms. Louise Lund, acting director of NRR's Division of Operating Reactor Licensing and co-chair, vice chair of the Fort Calhoun 0350 Panel, to make introductory remarks. Thank you.

MS. LUND: Thank you. Good morning. We appreciate the opportunity to provide an informational briefing to the ACRS this morning on the Fort Calhoun Station Inspection Manual Chapter 0350 oversight. Manual Chapter 0350 is the oversight of reactor facilities in a shutdown condition due to the significant performance and operational concerns.

And along with the welcome we got this morning, I'd also like to welcome our federal partner from the Army Corps of Engineers as well.

My name is Louise Lund, and I am normally the deputy director of the Division of Operating

Reactor Licensing in the Office of Nuclear Reactor Regulation, but right now I'm the acting director. But I'm responsible normally for Regions I and IV, and Fort Calhoun falls into my area of responsibility.

I'm also here today in my role as the vice chair of the 0350 panel for Fort Calhoun. And with me at the table is Tony Vegel who plays a key role obviously as the chair of the panel, and also in the side table, Mike Hay, who also plays a key role in the panel as well as Mike Markley who also plays a key role in the panel.

And Mike Hay is the branch chief for Fort Calhoun in Region IV, and Mike Markley is the branch chief in the Division of Operator Reactor Licensing here at NRR.

Together, today, we represent the panel, which also consists of the NRR project manager and a resident inspector at the plant and a non-voting member from the Performance Assessment Branch Division of Inspection and Regional support in NRR.

This oversight has been a comprehensive effort as I'm sure you will hear today by the staff with participation of many inspectors from all four regions, and support from the technical review staff and other supporting organizations here at headquarters including the Japanese Lessons Learned Directorate. The staff's review has been very thorough and involved a significant amount of effort which Tony will describe and it will be discussed in more detail today.

So with that I'm going to turn this over to Tony Vegel, the chair of the 0350 panel.

MR. VEGEL: Thank you, Louise. And thank you for giving us the opportunity to talk about Fort Calhoun performance, and in particular to talk about the Manual Chapter 0350 implementation over at Fort Calhoun.

Today, I hope to describe to you in the opening remarks at least to briefly talk about how Fort Calhoun got to increased agency oversight through the reactor oversight process, and then briefly tell you about why Fort Calhoun ended up there and what the 0350 oversight process, the activities of what we did in the last couple of years.

So with that first let me start out with the reactor oversight process. The reactor oversight process measures plant performance and it's basically two tiered. One, through a combination of objective performance indicators and, secondly, NRC inspection findings with a focus on reactor safety, radiation safety and safeguards.

Meanwhile, our seven cornerstones. The significance of findings is developed through a risk informed, significant determination process. And out of this process is issues that are determined to be either green, which is a very low safety significance, white, which is low to moderate safety significance, yellow, which means substantial safety significance, or the most significant or the high safety significance, which would be a red finding.

All this, as depicted on the slide, is based on the change to core damage frequency or the change in LERF which is large early release frequency. The reactor oversight process is designed if more issues of significance are identified agency oversight is increased.

In the case of Fort Calhoun Station, the reactor oversight process worked. Specific to Fort Calhoun, the sequence, and we'll cover this in more detail this afternoon, and also I believe that Fort Calhoun OPPD will discuss this as well, their timeline.

But the problem with Fort Calhoun where the reactor oversight process might be really worked, we had initially, back in 2010, identified a yellow finding related to the adequacy of flood protection action, and then in early 2011 the plant shut down for an outage. But then the flooding occurred and the plant remained in a shutdown condition, and this is about in the April time frame.

Soon after that the NRC issued a white finding which is involved with the reactor protection system, and when about that same time also an electrical fire occurred which eventually was determined to be a red finding.

So late in 2012, through the reactor oversight process we had a yellow finding as well as a white finding, which then placed the Fort Calhoun Station in Column 4, which if you look at the graph would be multiple/repetitive degraded cornerstone area.

And at the same time too, this is in the November/December of 2011, the plant was still shut down and they were in the process of taking flood recovery actions.

And based on those two conditions, the

plant performance issues, which was reflected in the yellow and white finding, and the plant still being in a shutdown condition due to the flooding, it met the criteria for entry into the 0350 increased agency oversight.

So the process worked through identified performance issues and also to ensure that after a significant event like the flooding that appropriate actions were taken to ensure that the plant would be ready to restart and that the recovery actions were complete.

MEMBER BLEY: Tony, are we going to come back to the various findings and the discussions of that later on?

MR. VEGEL: Yes, this afternoon I'll really go into detail on each one and go through the timeline in more detail.

MEMBER BLEY: That's perfect.

MR. VEGEL: Thank you.

So we end up in the 0350 process. And it may kind of give you a high level view of what is the Manual Chapter 0350. And sometimes the Manual Chapters as a title don't describe very well what it's about, this title is very good. Frankly, it's implemented if a plant has performance issues and if it's in a shutdown condition.

And, really, the Manual Chapter provides the guidance on how to implement the agency oversight at episode to ensure that there be a safe restart if the conditions are met, that all the contributing performance issues were addressed. And this is to ensure that -- and 0350 is more than just the restart piece of ensuring that the plant is ready for restart, but too when it's in the shutdown condition to ensure that it's safe.

And even when we take the next step, the big step is are they ready to restart. But then even after restart we continue to have oversight to make sure that the improvement actions being taken are being sustained.

The 0350 process describes establishment of a panel, and Louise touched on this. She's the vice chair, I'm the chair. The panel also included the regional branch chief which would be Mike Hay, the NRR licensing branch chief, Mike Markley is there. We have the project manager, Joe Sebrosky is also there. He was involved with that.

And then the senior resident inspector as well, and then any other staff that the 0350 panel thought it would be appropriate to have on the panel at different times. If we had security issues, we'd make sure that some of the security inspectors or management were involved in the discussions as well.

So the panel is truly a reflection of the agency. And when we implemented our inspections, it wasn't just Region IV resources or just Headquarters resources. It was all the other regions also providing inspection resources to make sure that we had close oversight of Fort Calhoun. And later this afternoon we'll talk about the number of hours and more of the specifics of our efforts in that area.

So the purpose of the panel is to coordinate the agency oversight both from an inspection piece, licensing actions, and a key part was to make sure that we were speaking from one voice both external communications and internal communications.

And we ensured that the focus was always plant safety during the shutdown and that safety could be ensured that corrective actions were adequate to support restart.

So this morning you will hear also from

OPPD, their perspective and their performance and the timeline of actions that they took to fix the problems.

And then you'll also hear from us that will provide more detail on the specific actions that we took from an agency oversight perspective and get, too, some specific examples of some of the issues and how we inspected them and how we ensured that the actions taken by Fort Calhoun were adequate.

So with that I think it's, that's all I was going to say for now and we'll be talking more, I guess, this afternoon.

CHAIRMAN SKILLMAN: Thank you. Colleagues, any questions for either Louise or for Tony? If none, then I'm going to invite our colleague from the U.S. Army Corps of Engineers, Jody Farhat, to please come and explain what I believe will be a very informative grouping of information relative to the control of the upper Missouri.

Jody, welcome and thank you.

MS. FARHAT: Thank you.

So my name is Jody Farhat. I'm with the U.S. Army Corps of Engineers. I'm chief of the Missouri Basin Water Management office, and my staff and I regulate the six dams located on the mainstem of the Missouri River.

I'm here to talk to you today to just provide an overview of the management of that reservoir system, and specifically to also talk about our operations for flood control and water supply which are the two of our authorized purposes that we would have the most dealings with Fort Calhoun Nuclear Station.

(Off the record comments)

MS. FARHAT: All right so the topics that I want to discuss today are the organization structure of the U.S. Army Corps of Engineers, again an overview of the operation of the Basin reservoir system, and also a bit of information on the Corps' emergency management efforts during flood fights.

CHAIRMAN SKILLMAN: Let me ask just for a second, Jody. Colleagues, do you have a copy of this presentation? Do you want a copy?

MEMBER CORRADINI: Yes, it's at the very bottom of the paper ones, and I think we've got an electronic one too.

CHAIRMAN SKILLMAN: Thank you. Please proceed, Jody.

MS. FARHAT: Next slide.

MEMBER BLEY: Well, since you were interrupted, may I?

MS. FARHAT: Okay.

MEMBER BLEY: I think this question really belongs towards your findings slides, but let me just ask you. Sometime during your talk if you would indicate to us how the relationship works through whatever government arrangements there are between the nuclear business and the NRC and your activities. I've heard bits and pieces of that but I don't know the story very well. So wherever it's appropriate.

MS. FARHAT: Okay. I think towards the end when I talk about --

MEMBER BLEY: Okay, that's good.

MEMBER CORRADINI: So, well, maybe you're going to get, I don't want to get ahead of you, but are you in the Northwestern Division?

MS. FARHAT: That's correct.

MEMBER CORRADINI: Okay, thank you.

MS. FARHAT: So the Corps of Engineers is part of the Department of Defense, Department of the Army. There are nine divisions within the Corps of Engineers that my office is part of the Northwestern

Division.

And then the Northwestern Division also includes five district offices including a district office in Omaha and Kansas City. But again my office is part of the Division because we have regional implications of the operation of the mainstem reservoir system.

Our headquarters for the Corps is here in Washington, D.C., in the GAO Building, if any of you are familiar with that. I have a very small staff operating this reservoir system. We have 12 folks in my office, a total of eight engineers, a fisheries biologist, two IT specialists and a secretary. So it's a very small staff operating this very large reservoir system. So next slide.

Are there any questions about the organizational structure?

CHAIRMAN SKILLMAN: Jody, you referred to the system or the waterway as mainstem. Could you just expound on that a little bit please?

MS. FARHAT: Sure. So the dams that my office regulate are on the Missouri River itself not on the tributary rivers that feed into the Missouri. So we call them mainstem reservoirs, dams and reservoirs.

CHAIRMAN SKILLMAN: Thank you.

MS. FARHAT: In the Missouri River Basin there are also, I believe, 45 tributary dams on the various tributaries that lead into the Missouri River. Those are operated by the Omaha and Kansas City District Water Management offices.

My office also has oversight responsibility for the operation of those projects, but our day-to-day operation is just on the six dams that make up the mainstem system and better shown on this current slide here.

So we have Fort Peck Dam in eastern Montana, Garrison Dam in central North Dakota, Oahe, Big Bend and Fort Randall Dams in South Dakota, and Gavins Point Dam on the South Dakota/Nebraska border. So it's seven very large dams.

We also consider part of the system to be the Bank Stabilization and Navigation Project which extends from Sioux City, Iowa to St. Louis, Missouri.

MEMBER BLEY: Are any of those tributary dams on waterways that are large enough that they'd have a real impact on your system during flood times?

MS. FARHAT: There are some tributary dams up in Montana, Wyoming and the Dakotas that we coordinate with, but our mainstem dams are much, much greater than any of those dams so really don't have a lot of impact on our operations.

MEMBER CORRADINI: Greater, the determination in greater is open gate flow capacity or is that B

MS. FARHAT: Storage capacity.

MEMBER CORRADINI: Storage capacity, okay.

MS. FARHAT: Yes, storage capacity.

MEMBER CORRADINI: So acre-feet.

MS. FARHAT: Acre-feet of storage capacity.

MEMBER BROWN: So they would be much less than the ones in the summary that we were given before, like Gavins Point, Big Bend. Those were fairly small relative to the big ones.

MS. FARHAT: And even those would be much, much greater than the other tributary dams.

MEMBER BROWN: Who actually, with your small staff, who actually owns and runs the specific dams? I assume there's a staff at the dams, but there's --

MS. FARHAT: Right.

MEMBER BROWN: Who does that?

MS. FARHAT: These dams because they are located in the Omaha District of the Corps of Engineers are staffed by Omaha District folks, their operations folks. Each of the mainstem has a operations project manager.

MEMBER BROWN: But are they part of the Corps of Engineers?

MS. FARHAT: Part of the Corps of Engineers, right.

MEMBER BROWN: So you're just the regulatory aspect of it. Okay.

MS. FARHAT: Right. So my office will tell them the amount of water to release out of each dam each day, and how to do that in terms of --

MEMBER BROWN: Okay. So they maintain and you tell them when to open the faucet or close it.

MS. FARHAT: Right. We also work very closely with the Western Area Power Administration, because Western Area Power Administration markets energy produced at the six dams, and virtually all of our releases will be passed through the hydropower units.

So it's a coordination between us, Western

Area Power Administration and the operators there on the ground at each of the projects. So they would have typically 40 to 60 employees on the ground at each of these projects to cover all of the maintenance, the operations folks and also the park rangers. A lot of staff on the ground there.

CHAIRMAN SKILLMAN: How much hydropower are we talking about, how many megawatts?

MS. FARHAT: About 2,500 megawatts at the total of the six dams. Okay, so we B

MEMBER BROWN: You're talking about power management. And that's a commercial or a civilian operation or is that a government?

MS. FARHAT: It's government. Western Area Power Administration is another federal agency. So they market the energy produced at the Corps of Engineers and the Bureau of Reclamation dams.

MEMBER CORRADINI: So maybe you're going to get into this. So given unusual events, what trumps what? That's the thing that most intrigues me is that so is power on the low end so if something occurs you have to, so are you going to get into that eventually?

MS. FARHAT: Well, yes, I can talk about

that here though. I've listed here on the slide the congressionally authorized project purposes. Flood control, navigation, hydropower, irrigation, recreation, water supply, water quality, and fish and wildlife which includes our Endangered Species operations.

So in a flood event, flood control obviously trumps all. And all of our operations, for example, in 2011, were focused on flood control. In a more normal period, like today, we're looking at all of these authorized purposes as we make our daily release decisions at the mainstem dams.

MEMBER CORRADINI: And if I might just ask, so just in the two extremes you said, under, there were flood situation, flood control trumps all and then normal operation. Under flood control is there an emergency operating procedure that populated areas greater than X are more worrisome than farmland with -- what I'm trying to figure out is there's a lot of land. So --

MS. FARHAT: How do you prioritize different regions' needs and it gets more important.

MEMBER CORRADINI: Yes, who wins?

MS. FARHAT: We try to operate to provide the best balance of flood control at all the locations. The major metropolitan areas that are impacted are the Omaha/Council Bluffs area, Kansas City, Missouri, and then down into St. Louis, Jefferson City, Missouri, also the capital of Missouri.

But we also have Pierre, South Dakota, Bismarck, North Dakota, but typically those areas because they are directly downstream of the reservoirs don't see major impacts from flood control. So our primary flood control operations are focused downstream at Gavins Point. In an event like 2011 though we had flooding all the way from Fort Peck down to St. Louis.

MEMBER CORRADINI: You had it all the way from where to where?

MS. FARHAT: From Fort Peck, Montana --

MEMBER CORRADINI: Oh.

MS. FARHAT: -- down to St. Louis. So along the entire stretch.

MEMBER CORRADINI: And then the last piece of it since it's a balance, which I gathered would be the case, does it fall upon you and your staff to make the final call? How does opening one versus another, does it come down to you?

MS. FARHAT: Yes, we're making --

MEMBER CORRADINI: Your staff. Excuse me.

MS. FARHAT: Yes, my staff is making the daily operational decisions at each of the dams certainly in major events in coordination with our leadership including the commander of the Northwestern Division.

MEMBER REMPE: Are there guidance documents that help them make those decisions? You've thought about it in advance and --

MS. FARHAT: Yes, and I'll get into that in a few slides.

CHAIRMAN SKILLMAN: Jody, is there any specific consideration for Fort Calhoun and Cooper in your protocol?

MS. FARHAT: There's nothing that specifically addresses Fort Calhoun --

CHAIRMAN SKILLMAN: Or Cooper.

MS. FARHAT: -- separately from all the other utilities and businesses located along the river.

CHAIRMAN SKILLMAN: So if I can just, going to use plant lingo. If you decide to open the gates it's the plant operators beware. The water's coming, get ready for it and hopefully you're designed for it. Is that pretty accurate?

MS. FARHAT: The Corps of Engineers does have the ability to provide assistance to states and local governments and even down to the utilities, but we are not in coordination with Fort Calhoun or any of the other --

CHAIRMAN SKILLMAN: Or Cooper.

MS. FARHAT: I'm sorry, or Cooper.

MEMBER CORRADINI: But you would be with the utilities though.

MS. FARHAT: Pardon me?

MEMBER CORRADINI: You would be with the utilities, not the plant itself? That's what I was trying to understand by your answer.

MS. FARHAT: Not directly, no. We wouldn't be. My office would not be in direct contact with the utilities during an event unless they happened to call me and ask questions.

MEMBER CORRADINI: So just a scenario so I get it. So there's a potential action. The plant calls their owner/operator, the owner/operator calls somebody and the somebody calls you? I'm trying to understand the report, the communication path.

MS. FARHAT: Right. And again one of the last two slides that I have talk about the Corps' operations during a flood. We have an emergency management office in the Omaha District that my office would coordinate with very frequently during that flood event.

The emergency management office's protocol is that they work with the states and then the states would work with the counties and local governments who then in turn would work with the utilities.

MEMBER CORRADINI: Okay, fine. Thank you.

CHAIRMAN SKILLMAN: Thank you, Jody.

MS. FARHAT: Next slide.

MEMBER BROWN: Let me ask one other question relative, if you're going to address it. I'll look at the last couple of slides. I presume there's already identified points of contact that can make decisions at each of these stations so you don't have to go searching for somebody up and down the chain. Is that B

MS. FARHAT: That's correct. And they have, with the emergency management folks, have annual exercises with the states to make sure that they have the proper communication set up.

Moving on to Slide 5. This slide just provides a graphic depicting the storage capacity of all the Corps of Engineers dams in the country to give you some perspective of the scale of the mainstem reservoir system.

So Garrison, Oahe and Fort Peck are the three largest Corps of Engineers dams in the United States, and we think of our system as having three large dams and three small dams. Big Bend, Fort Randall and Gavins Point being our three small dams, but Fort Randall is even the fifth largest Corps of Engineers dam in the country.

So it is a tremendous system, the largest system of reservoirs within the United States.

CHAIRMAN SKILLMAN: Jody, could you tell us what the large dams are in the East?

MS. FARHAT: I don't happen to know, I'm sorry. I could look that up for you.

CHAIRMAN SKILLMAN: Just a curiosity question because we might be more familiar with some of those than we would be with the ones on the mainstem system.

MS. FARHAT: I don't happen to know

CHAIRMAN SKILLMAN: That's all right. Thank you.

MS. FARHAT: -- the names of the other ones. I'm sorry.

CHAIRMAN SKILLMAN: Thank you, Jody.

MS. FARHAT: Okay. All right, next slide. So the mission of my office is to regulate the system of dams to serve these congressionally authorized purposes that I mentioned earlier.

I do always like to point out that flood control is different than the other seven authorized purposes because to operate for flood control it requires that you have empty space in the reservoirs. You know, the availability of empty space is what allows us to reduce peak flows, you know, to reduce flows coming into the reservoir, make the flows going out be smaller and provide flood reduction.

All of the other authorized purpose either require us to release that water, for example, hydropower, the only way to produce hydropower is to be passing water through the dam, or to store it in the reservoir for something like recreation. So recreation is served by storing water in the reservoir creating a lake for folks to recreate on.

All right, next slide. So the operation of these six large dams on the Missouri River are guided by what's called the Missouri River Master Water Control Manual, or as we call it, the Master Manual.

The Master Manual was first published in 1960. The reservoir system was built, Fort Peck in the 1930s, the remaining dams were authorized by the 1944 Flood Control Act, and they came online between the mid '40s and the mid '60s.

So the first manual was published in 1960, and then we had some minor updates in 1975 and 1979. Then in 1989, when the reservoir system went through the first drought that it experienced since reaching the full operating capacity, we went through an extensive drought and the reservoir elevations dropped significantly and that prompted the Corps to agree to revise or to review and if necessary revise the Master Manual.

So that process started in November of 1989. At the same time we were in consultation on and off with the Fish and Wildlife Service on our operation for Endangered Species. We received a series of biological opinions, the last in December

2003, and then in March 2004 the Master Manual was revised.

It took as you can see nearly 15 years to revise the Master Manual. It was a very sensitive issue with lots of input from the Basin states and the public and it was completed in March 2004 under a judge's order.

MEMBER CORRADINI: So if I might ask, so back to your flood control needing empty space, with the new Master Manual procedures does that create more empty space or less empty space?

MS. FARHAT: No.

MEMBER CORRADINI: Under normal operational conditions.

MS. FARHAT: Right. The Master Manual, the largest change made in 2004 was the revision of the drought conservation measures. So basically that is how we serve things like navigation during periods of drought, and those changes that were made conserve more water in the reservoirs.

The flood control storage designated in both what we call our annual flood control pool and our exclusive flood control pool has not changed in the Master Manual revision. So it's the same volume of flood control storage as it's always been and we did not change the manner in which that's operated.

MEMBER BALLINGER: It seems like there's two things that they're almost at cross purposes, flood control on the one hand and drought control on the other. Drought control says keep all the water in the dam so that you can use it later on. Flood control says wait a minute.

So how is that balance struck? Does this manual say do this because of this, that kind of thing?

MS. FARHAT: Right. So the manual is the guideline that helps us strike that balance between the authorized purposes. To ensure that we always have sufficient flood control capacity available to control the floods that are anticipated in the Basin, but also to ensure that we can provide service to those other seven authorized purposes during periods of extended drought.

And in the Missouri River Basin we have had periods of extended drought. The conservation storage in the reservoirs was designed to serve those seven authorized purposes during an extended drought like that of the Dust Bowl eras of 1920s and '30s.

CHAIRMAN SKILLMAN: Jody, when you mentioned provision for navigation and control of the water releases, is the target for the inventory of water the navigable part of the Mississippi below Kansas City or are you flooding, or providing navigation into the upper reaches of the Missouri and if so how far?

MS. FARHAT: Right. Our operation for navigation extends just from Gavins Point Dam to the mouth of the Missouri River at St. Louis. So we are only providing service to Missouri River navigation.

CHAIRMAN SKILLMAN: And what is the traffic up through that part of Nebraska and Iowa? What's going up and down through there?

MS. FARHAT: In terms of the commodities?

CHAIRMAN SKILLMAN: Yes.

MS. FARHAT: Actually there's very little movement of commodities upstream of Kansas City, Missouri. Between St. Louis and Kansas City there's asphalt, there's sand and gravel.

CHAIRMAN SKILLMAN: So it's basically shallow barge traffic, it's not deep-sea navigation.

MS. FARHAT: Right. Right. We provide a nine-foot navigation channel --

CHAIRMAN SKILLMAN: I see.

MS. FARHAT: -- which allows an eight and a half foot draft.

MS. FARHAT: Thank you, Jody.

MEMBER SCHULTZ: Jody, as this Master Manual is updated to address different issues that affect the Division are other master manuals also under review and revision accordingly? I mean does that work affect what happens in other divisions, other systems?

MS. FARHAT: Each system would have its own manual. This manual is called the Master Manual because we operate the six reservoirs together as a system. If there are individual reservoir projects, you know, located on tributaries, they would each have their own separate water control manual.

And so those manuals would be reviewed and updated as needed, but not necessarily impacted by --

MEMBER SCHULTZ: So there needs to be a forcing function generally that is like the ones that you describe here that cause the manual to be updated?

MS. FARHAT: I think ideally, you know, our regulations say that we would review each of these manuals every ten years, but certainly because of budget issues that doesn't happen.

MEMBER SCHULTZ: Thank you.

MEMBER BALLINGER: I have sort of another question. There has to be some sort of upstream or ahead of time predictability for these things. In other words, we think that we're going to need this much water here or we're going to release this much water there, how far ahead do you guys plan? Because, you know, there's a time delay between opening the valves and the water getting to places.

So like the spring runoff happens and things like that. So how predictable, year in and year out, are the things that you have to do?

MS. FARHAT: I have to say that it's not as predictable as we wish it was. We do run reservoir regulation studies that look out for the following calendar year, so right now we've put out what we call an annual operating plan, a draft annual operating plan that's looking out through all of 2015.

But that's based on historical runoffs, looking at a variety of runoffs. When we get into the actual year we're producing a monthly runoff forecast and then we update that every week and then every day as we make our release decisions.

But the predictability, I have another slide here that shows how the runoff has varied on a year-to-year basis in a very extreme manner in some cases. And so in most cases, except for things like snowpack that we can watch it accumulate during the winter and then melt in the spring that would be the most predictable aspect of our operations. But it does account for, you know, more than half of our annual runoffs, so in some sense that's somewhat predictable.

Okay, we'll move on to the next slide. So if you took the six mainstem dams and rolled them into one, the total capacity of that system would be about 72-1/2 million acre-feet of storage. And it's divided into four unique zones for the purpose of operations.

So starting at the bottom we have the permanent pool which contains 25 percent of the total storage capacity of the six dams. The permanent pool is meant to provide storage space for sediment that accumulates in the reservoirs over time. It also provides the minimum pools for fisheries and the minimum heads for our hydropower units.

And then what we have above that is called the carryover multiple use zone which is slightly over half of the total system storage. I always refer to this as our bank account for drought.

So when this reservoir system was designed, the folks who designed and built these reservoirs had in mind the fact that we want to be able to serve those seven authorized purposes that require water during an extended period of drought like that of the 1930s.

MEMBER CORRADINI: And all of these dams, I guess I was going to ask that. All of these dams are historically after the Dust Bowl era?

MS. FARHAT: Yes. Well, Fort Peck was started during, I think in late 1920s or early 1930s.

MEMBER CORRADINI: So in some sense these dams were in response to.

MS. FARHAT: Yes.

MEMBER CORRADINI: Okay.

MS. FARHAT: Yes, very much so. So that's why we have these humongous reservoirs out on the northern Great Plains. Above the carryover and multiple use pool is what we call the annual flood control and multiple use pool. This is the desired operating range of the reservoirs.

So in an ideal world we would start each runoff season at the base of this zone, at 56.1 million acre-feet of storage. As we receive the melt of the Plains snowpack in March and April and then the mountain snowpack in May, June and July, we would fill into this zone, capture the water and then meter it out through the remainder of the year to serve those authorized purposes downstream and arrive right at the base of this annual flood control and multiple use zone by March 1st of the following year. So that's ideally we would fill and then evacuate that water in a calendar year.

MEMBER BLEY: So when everything's going right you stay in that little --

(Simultaneous speaking)

MEMBER CORRADINI: So you go from 72.4 to 56.1 if life is good.

MEMBER BLEY: Yes.

MS. FARHAT: Actually, 56.1 to the 67.7.

MEMBER CORRADINI: Oh, excuse me.

MS. FARHAT: So that's the ideal operating zone. And then above that which makes up seven percent of the total storage is what we call the exclusive flood control zone. And so this is storage that is reserved in the reservoirs exclusively for flood control, and when we get into this zone we are operating specifically for flood control.

And we try to evacuate water that's in that zone either in individual reservoirs or in the system as a whole as quickly as downstream conditions permit.

I do want to point out that what this looks like physically out on the projects is this is the top of the spillway gates when they are in the closed position. It's not the top of the dams. There's another 20 to 40 feet before we get to the top of the dams.

But this is the point in storage where the reservoir elevation will begin to control the releases. We do not ever want water to flow over the top of our spillway gates because that could prohibit us from opening them if it continued. So we would always want to keep water below the top of the spillway gates.

MEMBER CORRADINI: So can I use an analogy?

MS. FARHAT: Yes.

MEMBER CORRADINI: So I'm in my bathroom. I unexpectedly plug it. It comes up, the little hole at the top, somewhere in the basin is a spillway gate. You don't want to get over that because somehow the operation of the spillway will be impeded, potentially?

MS. FARHAT: Right.

MEMBER CORRADINI: Is that what I hear you say?

MS. FARHAT: Yes.

MEMBER CORRADINI: Okay. And then the second part of the question is, so did the blue and white regions change with the 2004 new Master Manual, or all those remained the same?

MS. FARHAT: The storage zones all stayed the same but the manner in which we serve navigation changed. So today, we, during a period of drought we reduce service to navigation sooner and more severely during a period of drought. So as the reservoir storage goes down, we reduce flows for navigation and then we shorten the navigation season sooner.

MEMBER CORRADINI: But in terms of flood control, nothing changed in the 2004 Master Manual to the prior --

MS. FARHAT: Correct.

MEMBER BALLINGER: So when you get to the top of the gate you have to release water.

MEMBER BLEY: Before.

MS. FARHAT: We're releasing water from all of these dams every day, but certainly when we get to the top of the gates, you know, we need to be opening the gates to provide additional storage capacity.

MEMBER BALLINGER: Have there been cases where you've had to?

MS. FARHAT: Typically, you know, we've had water to the top of the gates at some of the dams on rare occasions, and on the occasions that I can think of right now we were already operating those gates at the time that the water reached the upper gates.

CHAIRMAN SKILLMAN: So was 2011 an example?

MS. FARHAT: Yes. And it's a little misleading here, because during 2011 that total storage capacity of the dam was 73.1. So we were not above the top of the exclusive flood control zone in 2011. We were very close. We were 300,000 acre-feet below it.

But since that time we've gotten new

reservoir surveys, sediment surveys in for five of the six dams and that has reduced the total storage capacity about 700,000 acre-feet.

MEMBER CORRADINI: So there's junk at the bottom of the dams that have reduced your volume, your evacuated volume.

MS. FARHAT: Sediment has filled in some of the storage capacity, as anticipated. But it was built in.

MEMBER BLEY: Just to balance an earlier question, in that second zone, the annual flood control zone, a question about repeatability every year. Are there many years in which you actually can stay within those bounds or do you usually drift out one way or the other, or is it about half and half?

MS. FARHAT: There are many years that we can stay within, and I didn't bring it but we do have a graphic that shows over time how we've managed through these zones.

And there was a long period of time from 1967 up until that first major drought, 1989, that we operated very tightly in that zone with only a few times where we dipped into the carryover multiple use zone or into the exclusive. So it is possible. In the last few years we've operated in a very wide range.

MEMBER BALLINGER: So when you gradually get sediment reducing capacity, you use percentages here, do those percentages stay the same or does that capacity come out of something?

MS. FARHAT: The percentages can change, but to date we have not ever had to adjust the elevation that represents the base of the annual flood control zone at the reservoirs. If the sediment came into the upper end of the reservoirs and which caused us to lose flood control capacity, we would go in and change what we would consider the top of the conservation pool at the reservoirs to preserve that.

MEMBER CORRADINI: So just to say your answer kind of to Ron, so if there's more sediment after you do a survey in the time that you surveyed and then surveyed again, is it affecting the permanent pool or it depends on the reservoir?

MS. FARHAT: It depends on the reservoir.

MEMBER CORRADINI: Okay, that's what I thought you were trying to get to.

MS. FARHAT: Yes, yes. To date we have had pretty much a balance. Sediment does come into the upper reaches of the reservoirs into that exclusive flood control and annual flood control zones, but we also along the shores of the reservoirs get some sluffing which has the effect of increasing the storage capacity at a lower elevation so they have balance.

But it would be our objective to always maintain that same total volume of flood control capacity. And if that meant that we had to lower the reservoir elevation in order to do that we would do that.

MEMBER RICCARDELLA: This diagram kind of implies it's a single thing, but are these numbers the aggregate for all the dams?

MS. FARHAT: This is the aggregate of the storage. And then each of the reservoirs would have a similar diagram and you could include both storage and elevation with that.

MEMBER CORRADINI: But the percentages are the, I guess I was a follow-on to Pete's. The percentages in your six reservoirs within plus or minus epsilon are the same?

MS. FARHAT: No.

MEMBER CORRADINI: Oh, they're not?

MS. FARHAT: Not at each of the six reservoirs.

MEMBER CORRADINI: Okay.

MEMBER RICCARDELLA: But you can balance them, I assume. You can do some balance there.

MS. FARHAT: Yes, we do do some balancing and what we call intrasystem regulation in order to balance those. And particularly when I talk about balancing we're talking about the upper three reservoirs because nearly 90 percent of the total storage is in those upper three reservoirs.

And so when we go through a period of drought, we would like the percent of the carryover multiple use zone remaining to be balanced between those reservoirs so that one reservoir isn't significantly more impacted by the drought than another reservoir.

MEMBER BALLINGER: So where did the water come from that went by Fort Calhoun?

MS. FARHAT: That water came from the entire upper Missouri Basin.

MEMBER BALLINGER: Yes, but there's a basin that drains downstream of these dams, right?

MS. FARHAT: Correct.

MEMBER CORRADINI: Right. But Gavins Point, unless I misunderstood the plot, the Gavins Point is the nearest. But your point is since 90 percent of all the stuff is upstream of Gavins Point, they dominated whatever Gavins Point had to do because it didn't have enough storage to do anything anyway.

MS. FARHAT: Correct. So the --

MEMBER BALLINGER: So the distance from the Basin to below Gavins Point is really not that much.

MS. FARHAT: In 2011 it was significantly lower than what was coming from the upper Basin, but there are other events like we had this summer where Gavins Point releases were very low but we've had very high runoff from that incremental area between Gavins Point Dam and Fort Calhoun. Yes.

MEMBER SCHULTZ: The next few slides will help.

MEMBER CORRADINI: Maybe I could ask Dennis' question a different way. I'm sorry. But what I thought Dennis was asking, save for 2011, if you started putting the historic markers of where your levels were, did anything rise up to 2011 or was it so unique that if I just started plotting year after year all my little red lines would be way down in the next blue column? That's what I thought you were kind of asking.

MEMBER BLEY: I was looking at the variability overall, but yes, that's an aspect of it, sure.

MEMBER CORRADINI: If you just start plotting all the years, would they all just accumulate into the annual flood control multiple use thing or would some of them start reaching up to where 2011 was?

MS. FARHAT: Some of them would reach up into the exclusive flood control pool. I think our prior maximum system storage was 72.6 million acre-feet and I believe that was in 1975 or '78. I'd have to go back and look.

MEMBER CORRADINI: Okay, fine. Thank you.

MS. FARHAT: So if we look at the six individual mainstem reservoirs, and this gets to the question earlier, this is what the individual reservoir storage capacity is with the four different zones shown for each of the reservoirs.

So you can see that the bulk of the carryover multiple use storage, which is the light grey or white area shown on those graphics, the bulk of that is in Fort Peck, Garrison and Oahe. Fort Randall has a small amount.

And again the annual flood control and exclusive flood control is also primarily in those upper three projects, plus Fort Randall. Big Bend is really a hydropower plant.

All the water that comes into Big Bend from Oahe is passed out, you know, within 24 hours so it's pretty much, it stays a very constant elevation ranging typically only about a foot between the high and low pools annually. And then Gavins Point is what I would call our re-regulation dam.

At the other five dams, the releases can vary hourly as needed to serve the hydropower demands. So, for example, at Oahe it may be shut off for all night long and come on first thing in the morning when the power demands increase. And so the other five dams can do that varied releases within a day.

Gavins Point Dam, because we're serving navigation downstream, we have a constant release out of that project in order to provide constant flows in the river downstream.

And to give you a sense how small Gavins

Point Dam is compared to the other dams and compared to what our releases were in 2011, at the volume of our releases in 2011 we were completely replacing the water in Gavins Point Dam every 36 hours in 2011.

So it was really just a flow-through project. We were managing flood water that was stored in the upper three projects and in Fort Randall.

MEMBER CORRADINI: So for all intents and purposes, Gavins Point didn't exist.

MS. FARHAT: Correct.

MEMBER BLEY: It looks like Big Bend is probably almost the same.

MS. FARHAT: About the same. Yes. It has a little bit larger total storage capacity but very little ability to impact flood operations.

MEMBER RAY: Other places it's called a run of the river.

MS. FARHAT: Run of the river, yes. That would be the right term.

Okay, next slide. So if you look at the runoff components for the mainstem dams, we get runoff from Plains snowpack, and this would be typically in eastern Montana, North and South Dakota, and that runoff comes typically during the months of March and

April and constitutes about 25 percent of our annual runoff.

And then we have mountain snowpack. That mountain snowpack is from the Rocky Mountains. It comes just into Fort Peck and Garrison Dams are the only dams that have drainage that includes mountain runoff. We typically get about 50 percent of our annual runoff from the mountain snowpack and that comes in the months of May, June and July.

And then the remaining 25 percent of the runoff comes through the remainder of the year as a result of runoff. And when I talk about the runoff, I'm really looking at the area above Sioux City, Iowa. So that's, I should have marked on here, but that's the runoff that we use to operate the reservoir system is the drainage basin above Sioux City, Iowa.

And I guess the important thing about that is the entire Missouri River Basin is about 529,000 square miles, the mainstem dams control the runoff from about half of that area. So getting to the question earlier about the area below, the drainage basin below the mainstem dams, it's about half of the total drainage area of the reservoir, of the Basin.

Okay, the next slide. This chart

represents our historic runoff dating back to 1898. This is the runoff period that we utilize when we develop our long range operating plans. We look at various frequencies of runoff associated during this time period.

So you can see that there's been a great deal of variability including periods of relatively normal flows, but also extended periods of drought from the drought in the 1930s to early 1940s. We had about an eight year drought in the 1950s to early 1960s, and this is the time that the reservoir system was being built and initially filled. So it wasn't a big concern at that time.

Then from the '60s to the late 1980s, we had a period of pretty normal runoff years and that would be a long period of operating in the annual flood control zone.

But then the Basin experienced the first drought beginning in 1987, the first severe drought since it first reached normal operating levels. That drought ended in 1993 with a great flood in the Mississippi Basin that covered the entire Mississippi Basin in 1993.

At the time, in the spring of 1993, we had estimated that it would take five years of normal runoff to refill the reservoirs because they were drawn down so much from that drought, and in fact they refilled in about six months because of the very high runoff in 1993.

Then we went through a fairly wet period in the '90s, followed by another extended drought in 2000 to 2007, where we reached our record lows that the reservoir system has had, and then back into a wetter period beginning in 2008 or '09.

MEMBER CORRADINI: So you had said that 1975, which was not the peak in the '90s but the next biggest peak, is where you hit something close to what was in '11.

MS. FARHAT: I think it was actually 1970, I --

MEMBER CORRADINI: Well, it doesn't matter.

MS. FARHAT: Okay.

MEMBER CORRADINI: What I guess I'm trying to get at is that one peak in the '90s you didn't mention so I was just curious. I would expect that would be probably the next big one.

MS. FARHAT: Yes. And actually, let me

just B

MEMBER CORRADINI: I mean I'm just trying to correlate what you're --

MS. FARHAT: Right. It was either '78 or '97 that we had that previous record high.

MEMBER CORRADINI: And then the other thing that I guess you said earlier, so the predictability is rotten. I mean if I started putting the little red lines, I guess, just by looking at this it's all over the place.

MS. FARHAT: It is.

MEMBER CORRADINI: It's oscillatory, but it's unpredictable after --

MEMBER SCHULTZ: Have you observed the floods in these areas in the last three decades?

MEMBER BLEY: But it's reasonably contained except for a couple of years too.

MEMBER RICCARDELLA: The 24.6 is the mean, I assume?

MS. FARHAT: Yes.

MEMBER RICCARDELLA: And then what's the standard deviation?

MS. FARHAT: I don't know right off the top of my head.

MEMBER RICCARDELLA: We just want to see how many standard deviations that 2011 was.

MS. FARHAT: Okay. I misspoke earlier. Our previous peak system storage was in 1997.

MEMBER CORRADINI: That's okay. I wanted to just make sure I was correlating X to Y, so that's fine.

MEMBER BLEY: But even in the periods of drought you're probably producing a few times only 50 percent but usually 70 to 80 percent of normal electric power coming out of those things.

MS. FARHAT: During 2005-2006, I think our power generation was down to less than half of normal.

MEMBER BLEY: Less than half, okay.

MS. FARHAT: Yes, when the reservoirs were drawn down.

MEMBER BLEY: I'm guessing everything that's spilled that's used for any other purpose is also generating power as it goes through, or not always?

MS. FARHAT: Virtually all of our releases will be passed through the hydropower units. The only time that we spill water either through a spillway or through an outlet tunnel is if we don't have sufficient capacity at the power plant.

MEMBER CORRADINI: So maybe you said it in your last answer and I didn't understand it. But so when you release it, so on the three peak points you already know the expected flooding in the downstream that it's going to rise X amount and people are aware?

MS. FARHAT: Right.

MEMBER CORRADINI: I shouldn't say people. State and local governmental authorities are aware what to expect?

MS. FARHAT: Right. We work with the National Weather Service, the Missouri Basin River Forecast Center. They are the official river forecaster for the Missouri River Basin. So we work with them on a daily basis and let them know what our planned releases are from the reservoirs and then they produce a daily river forecast.

MEMBER CORRADINI: Okay, thank you.

MEMBER BALLINGER: And how much lead time can you give somebody? When you start to see a pattern in reservoir use, how far in advance do you tell somebody, look, we're going to have to release at this point. You should plan on something happening some --

MEMBER BLEY: In hours, days or weeks, I think is what he's

MEMBER BALLINGER: Yes, yes.

MS. FARHAT: And I'd have to say it depends. It terms of the reservoir releases, we can generally give days' to, you know, weeks' notice in terms of our reservoir release.

We typically have enough capacity that we can manage a few days of inflows before we have to make a major release change. Like in 2011, at the end of May we announced what our peak releases were going to be and we actually reached that peak release in the middle of June. So in that time there was some advance warning.

The difficulties become the travel time from the dam to downstream areas and impact of this local drainage area. So the travel time from Gavins Point Dam down to the Omaha area, which is just south of Fort Calhoun, is about three, three and a half days.

And so if we get a heavy rain in that reach we could make an immediate release reduction, but it isn't going to make any difference for a couple days to get down to that area. And then the travel time down to Kansas City is about five and a half days, and about ten days down to St. Louis. So our ability to provide flood protection is reduced as you move further away from the reservoirs.

MEMBER BALLINGER: So when civilians like me listen to the radio you hear the words like, we expect the level of this river to peak at X at a certain time. That's the information that you give them?

MS. FARHAT: I've passed my release information on to the National Weather Service and they are the ones who are actually predicting river stages.

MEMBER BLEY: But they're looking at local drain too.

(Simultaneous speaking)

MEMBER BALLINGER: Below Gavins Point.

MS. FARHAT: Okay.

MEMBER RICCARDELLA: I assume 2014 you've projected to year end?

MS. FARHAT: Yes, that's the projection through the end of the year. And I think it's important to point out here too, in 2011 we had our record high runoff, 62 million acre-feet of runoff, just nearly two and a half times the average annual runoff. In 2012 we had less than a third of that. We had less than 20 million acre-feet. So the variability is extreme.

MEMBER RICCARDELLA: And it seems to be increasing.

MS. FARHAT: And it does seem to be increasing. And we just had NOAA do a report for us. It was at what we call an attribution study to look at what was going on in the atmosphere to cause the 2011 flood, and basically they said, you know, a lot of bad things happened at the same time.

In 2011 there wasn't, you couldn't point to just an El Nino or a La Nina or Pacific decadal oscillation. But they pointed out that variability increasing and the fact that nine out of our ten highest years have happened in the last 30 years. So the next --

MEMBER CORRADINI: And a good portion of --

(Simultaneous speaking.)

MEMBER BALLINGER: About 2025 we should expect the end of life as we know it because of linear progression.

MEMBER REMPE: Right. This is on the record.

(Simultaneous speaking)

MEMBER RICCARDELLA: You know, it was 2011, could you zero in on any one of those three?

MS. FARHAT: 2011 was all three of those components.

MEMBER RICCARDELLA: All three. So the percentages stayed about the same but everything was high.

MS. FARHAT: Yes.

MEMBER CORRADINI: The variability is nice --

MEMBER RICCARDELLA: I remember it as being a particularly good ski year.

MEMBER BLEY: No, so it's not just been better, it's also looking like it's -- right. Then the flows on this --

(Simultaneous speaking)

CHAIRMAN SKILLMAN: Well, I really appreciate this. Because, you know, if I'm a plant operator, if I'm sitting at Cooper or Fort Calhoun and I'm saying, okay, I've got these real strong deviations and they seem to have some periodicity, and

I'm beginning to think maybe I better start making some provisions to make sure that if I've got a water event I'm so far ahead of it I do not have a problem.

I mean it's kind of a ding-a-ling, because I say that for those many years I was at TMI. We had that same question, you know, what are we going to do if we back up the Susquehanna? Because we're going to have water everywhere.

MEMBER BLEY: But we're just looking at the Missouri River watershed here. I don't know what the others are doing. Are they doing the same thing?

MS. FARHAT: Others in the nation?

MEMBER BLEY: Yes.

MS. FARHAT: I can't speak to that directly.

MEMBER CORRADINI: So actually Dennis' point, I guess, would be an intriguing one. So does your region or your district communicate this sort of information up the chain and somebody within the Corps is going, hmm? No?

CHAIRMAN SKILLMAN: Ding-a-ling-a-ling.

MS. FARHAT: We do have in our headquarters hydrology and hydraulics lead there and we also have some research folks. And as I mentioned we had NOAA do a study for us.

And I think that if funding allows we'll have them do the next part of that study and to see if they can pinpoint why the variability has increased and why these extreme events have increased. But it would be nice if others were looking at it also.

MEMBER CORRADINI: Well, the only reason I ask, at least in my little local part of the world, this is in the university world, water control and also fluctuations like this is becoming a very big deal. So I'm just kind of curious if the Corps just communicates and so there's a place to go look at these trends nationally.

MEMBER BLEY: Let me ask it a different way. I did find your master water control manual for the Missouri. Is there a national water control plan? I mean they aren't coordinated anymore but that really isn't part of what the Corps is doing.

MS. FARHAT: No, the systems are operated independently.

MEMBER CORRADINI: So Bonneville, if that's what it's called, out West, is operated differently and you guys' is operated differently?

MS. FARHAT: Right.

MEMBER REMPE: But at some point why not just build a bigger reservoir or a big hole in the ground to accommodate the water?

MS. FARHAT: Well, and that's a very good question and we received that a lot after 2011, you know, why don't you just drain these reservoirs? But I think 2011, you know, was certainly a unique event but the volume of water was tremendous. And even, because the way we want to operate flood control is we want to have all of the flood control capacity available every year. We want to pass each year’s water through the reservoir system, end up right where we started.

In 2011 we had 62 million acre-feet of water. If you could release that water 365 days of the year, you know, with perfect foresight, it’s coming and you don't have any other restrictions, it would be about almost 85,000 cubic feet per second per day which is higher than our previous release we had ever had prior to 2011, which was 70,000.

And in the Missouri Basin we can't release water 365 days a year at that rate because of ice. So if you put a high release in the winter but, you know, something more reasonable, say, 30,000, which is more than we've ever done in the winter but we might be able to squeeze it out, that would end up with a release of over 100,000 for the other nine months of the year, which the flooding would have had about the same footprint. It would have lasted longer. It would have been slightly less deep.

So it's a volume issue. You have to pass all this water through in a single year. And that's the real challenge of 2011 that even having empty reservoirs, if we wanted to be prepared for 2012, this was going to be a major flood no matter what. Does that make sense?

CHAIRMAN SKILLMAN: Let's go. Thank you, Jody.

MS. FARHAT: So moving on, I have just a few bullets here about our regulation during extreme events. Again this is a tremendous reservoir system. We have a great amount of flood control system. It's designed to work through these extreme events, both floods and droughts.

The Master Manual provides the seamless transition between floods and droughts. We don't have a special drought manual that we pull out during times of drought and a flood manual. The Master Manual provides that oversight for all conditions.

And we have tweaked the operations over the years for things like the Endangered Species Act, but the overall operations haven't changed since the 1960s.

And the operation really depends on the amount of runoff that we get. It is a runoff driven system. If the runoff is very low coming in we're going to move into drought operations. There's nothing that we can do in the reservoirs to create additional water. Or again in the flood control operations, because we do flood control on a single year basis, you know, all of that year’s water has to be passed.

There have been changing conditions on the ground that have made our jobs more complicated including municipal and industrial intakes located along the river that weren't there when we originally built the reservoir system.

We have recreation facilities both in the reservoirs and downstream, and then we also have encroachment into the flood plain. Communities that are built very close and tight to the river in some areas.

So that has made our operations more difficult. And the river channel itself also continues to evolve. We have reaches of the river where we have degradation or a lowering of the streambed which provides additional channel capacity, but we also have other reaches that have aggradation or the depositing of the sediment that reduces our channel capacity.

So all of this is a dynamic environment which impacts our ability to make releases and to serve all those authorized purposes.

And then we get a lot of questions about climate changes. Is climate change the reason we're seeing the variation in runoff that you saw in the previous slide.

And I think, you know, they're aren't, there's differing opinions, but I think most everybody agrees that with climate change we'll spend more time on both ends of the hydrologic spectrum. More times in severe extended droughts, more time in floods.

MEMBER SCHULTZ: Jody, with respect to runoff measurement, I'm talking about that runoff above Sioux City, is there good confidence in the data early in the last century, 1900 to 1930, for example, but presented here as all the accuracy, these measurements are the same, and is that true? Can we give equal confidence to all these measurement for that runoff measurement?

MS. FARHAT: Prior to 1930 there were only a few river gauges in the Missouri River Basin. so that record prior to 1930 is not, we are not as confident in that. But since 1930, we've had really good --

MEMBER SCHULTZ: I would have picked that as a time when attention would have been paid to measurement.

MS. FARHAT: Right, right.

Okay, this is a calendar of events. It just shows some of the different considerations that occur typically at these times of year. I won't spend a lot of time on this because we're running a little behind here, but just to show you that there's different times of the year when our flood risk gets high, when we're operating for navigation or for fish spawns, irrigation and power.

CHAIRMAN SKILLMAN: Jody, what is the cross-hatched area at the end of each of the navigation seasons?

MS. FARHAT: In years that we have sufficient water we can extend the navigation season ten days.

CHAIRMAN SKILLMAN: Thank you.

MS. FARHAT: All right, now I'm going to focus on the two authorized purposes that probably are of most interest to you, flood control and water supply.

As I mentioned earlier, and we've talked about this quite a bit already, flood control requires empty space in the reservoirs, and then how it works is we capture the runoff during periods of high inflows and we meter that water out through the remainder of the year.

Again it's an annual operation. We want that flood control storage to be evacuated by the start of the next years' runoff season which is typically around the 1st of March.

And we can provide significant flood risk reduction downstream of the reservoir system and between the reservoirs, but there was never the intention that we would provide a flood-free zone, because of the incremental drainage areas and because of the need sometimes, like in 2011, to release massive amounts of water. And our ability to reduce flood damages reduces the further you move from that control point due to the travel time and the intervening area.

Water supply. Just focusing on the lower Missouri River, we have a total of 40 intakes between Gavins Point and St. Louis that are located along the river.

The picture is the water intake for the city of Omaha. Most of these facilities are hard structures on the banks of the reservoir that have been built since the reservoir system was put in place.

And the thing I'll say about water supply is there's always sufficient water in the river. Our releases every day are sufficient to serve the needs. No water intake takes more than one percent of the total flow in the river flowing past their intake on the lowest day.

But what the intakes have sometimes is an access problem. Because of the changing nature of the river, because of things like ice, they have difficulty sometime maintaining access to the water.

Our position is that we provide the water, it's the intake owners' responsibility to ensure access. And if it weren't that way you can imagine how difficult it would become. I mean we would have to release massive amounts of water, say, due to channel degradation just to serve individual intakes.

So we do make adjustments on our releases, and particularly we have challenges during the winter, for example, following the 2011 flood there was a lot of channel degradation. There were at least four water intakes that might not have been able to operate that winter, or I'm sorry, the following winter in 2012 after our dry year, and so we released extra water in order to give them an opportunity to make changes so that they can operate at lower levels.

But we encourage to do that. What we say is we meet the needs of the downstream water intakes to the extent reasonably possible. We don't believe it's reasonable to run a community, a large community, out of water so we release additional water, but we certainly want the intake operators to make the necessary adjustments that they need to in order to maintain access.

Okay. Now moving on to a little bit on the Corps' flood fight efforts. Again this is not my area of expertise. I received the slides from our emergency management office and I'll do my best to explain them.

So in the Corps of Engineers' PL 84-99 Program there's a procedure for the activation of federal resources to respond to a flood. So if you can follow the diagram through me, an event occurs. The local emergency manager would go to the county emergency manager and go to the state to coordinate resources and to respond to the event.

Once the state or the tribe's resources are fully utilized, if they need additional assistance then they can come to the Corps of Engineers. And only the states and the tribes can come directly to the Corps of Engineers and request assistance.

So that request for assistance would go into the Corps district office. For the Fort Calhoun area that would be the Omaha District Office of the Corps of Engineers.

They would coordinate up through our division office in Portland and up through headquarters to receive authorization and funding to respond. That would go back down to the district and they would provide a response directly to the locals.

MEMBER BROWN: Does that flood fight -- that's a nice terminology. When you say the response in the counties are going to direct it down to the state, does that mean that they would, in order to prevent or minimize flooding they would ask you to restrict releases? That's the only way I figured out you can stop downstream flooding is to restrict releases and start letting the reservoirs fill --

MS. FARHAT: Yes.

MEMBER BROWN: Was that

MS. FARHAT: That's not what's anticipated here. What's anticipated is that we would provide sandbags, we would build temporary levees. We would provide technical assistance on how to protect properties. It's not a request for us to change operations in the reservoirs.

MEMBER CORRADINI: So none of this would change your operational procedures. This is additional efforts you would help with the local communities.

MS. FARHAT: Correct.

MEMBER BROWN: So do you all maintain warehouses full of sandbags?

MS. FARHAT: Yes.

MEMBER BALLINGER: So what constitutes an event?

MS. FARHAT: An event, there's some criteria listed here that the rivers have to be at or above flood stage. The Corps' ability to provide a response, it must be to protect critical infrastructure. It can't be to protect individual homes or neighborhoods. There has to be critical infrastructure that would be protected by, say, a temporary levee.

MEMBER BROWN: This would be like power stations or sewage treatment plants --

MS. FARHAT: Yes, yes.

MEMBER BROWN: -- or something where you could have large scale civilian impact.

MS. FARHAT: Exactly. Those types of things.

MEMBER BROWN: So somebody's business, not necessarily, other than --

MS. FARHAT: Correct.

MEMBER BALLINGER: So you say it has to be at flood stage or above?

MS. FARHAT: Right.

MEMBER BALLINGER: So, there's no

anticipation of an event.

MS. FARHAT: Or forecast, yes. We can provide assistance in advance, assuming that, you know, this is supplemental to local and state efforts. So assuming that all of the resources of the state and local governments have been expended. So they would have the first shot at providing a response.

MEMBER BALLINGER: I'm just trying to get a handle on the delay time, the cycle time for this kind of thing where people, like at Fort Calhoun, when would they get notification and how much in advance would they get notification that it's time to start sandbagging?

MS. FARHAT: So the communication would go from, for example, the Omaha District Emergency Management Office through the state and down through the local government to Fort Calhoun Nuclear Station. I would assume that could occur very quickly, within a matter of hours. And then when the Corps gets a request, our response time especially in events that we see coming can be very quick. You know, less than 24 hours we can have resources on site. We can have engineers there, you know, looking at levees, providing sandbags and that type of --

MEMBER BALLINGER: But it's in response to water level that's already rising.

MS. FARHAT: Or an event that we can foresee.

MEMBER BALLINGER: What's projected. So is that three day --

MEMBER BLEY: No, that's after they release it. They might know weeks ahead of time that they're going to --

(Simultaneous speaking)

MEMBER BLEY: Isn't that what you're saying?

MS. FARHAT: Yes. In a typical event which would be a rainfall event, you know, like we had here in 2014, you know, the rain fell. By the next day we can see the gauges rising. You know, we would notify the states who would notify the locals, and there were folks on site that day providing assistance and making preparations.

And then so if the river is at or above flood stage that is for us to actually provide a response in terms of providing sandbags or building levees. We can also provide technical assistance at any time.

And again, like if Fort Calhoun wanted the Corps of Engineers to provide technical assistance on how to best protect their plant they could come to the Corps through the states. But that doesn't have to be in an emergency.

MEMBER SCHULTZ: Who is the "we" at that point? In other words this is not your eight engineers.

MS. FARHAT: Right.

MEMBER SCHULTZ: So rather, what resources are available to provide this support in the Corps?

MS. FARHAT: That is handled by the district offices. The Omaha District Office has 800 or 1,000 employees, something like that.

And during a big flood event they can also bring people in from other parts of the country and we did that in 2011. We brought in resources from throughout the country and we also have the ability to bring in retired employees, bring them back as rehired in emergencies.

MEMBER SCHULTZ: Okay.

MS. FARHAT: And then the last slide I have talks a little bit more about this flood fight doctrine, talking about an event occurs. It's really the district offices that are the front line providing assistance to the state and local agencies.

The request has to come from again from the state or a tribe. If it becomes a regional flood, the division offices become more engaged. And throughout the event we're working from the districts through the division offices up to our headquarters, sending requests for authority and funding, and then we get approval for, we get funds and tasks back.

MEMBER CORRADINI: So in the 2011 event that triggered all of this, are there lessons learned for how you responded in 2011 that you'd change the event management or did it just work as you expected it to?

MS. FARHAT: I think, we do an after-action review and certainly there were things that we thought we could improve on following the 2011 flood. There's always things that you can learn, especially from especially an extreme event like that.

But I think overall it worked very well. The districts were able to pull in resources and we had good support from our headquarters to provide all the support that we could and good coordination.

MEMBER BROWN: Do they have to go to the

region for response or even up to the national response in order to hit -- you said district, and so I was focusing it just seems that you went to the district and that seemed to work.

But the next question was then was it so bad that they had to go up to the regional and then up --

MS. FARHAT: We did have regional and national input into the response that allowed us to pull in resources from other districts and divisions.

MEMBER BLEY: This is where my earlier question was where it says national response coordination. I think that we've heard about in the past that there's some, either coordinating, national coordinating committee or some kind of formal arrangement where the agencies of all sorts, and in our case here at the NRC, can interact with other government agencies to work together in areas where they need help. Are you familiar with that kind of operation and how that works?

MS. FARHAT: I know that it exists but I'm not familiar with it. So I would provide status reports on a daily basis up to my headquarters. They have essentially an emergency operations center there who are doing the coordination at the national level.

CHAIRMAN SKILLMAN: Colleagues, do any of you have further questions for Jody at this point? Jody, I understand you're going to stick around for a couple hours just in case the members are focused on an item that might emerge later on?

MS. FARHAT: Yes, I'll be here through at least midafternoon.

CHAIRMAN SKILLMAN: Jody, thank you very much. For the whole committee, I thank you. We are adjourned for 15 minutes. Come back at a quarter after 10:00 on that clock.

(Whereupon, the above-entitled matter went off the record at 9:59 a.m. and resumed at 10:16 a.m.)

CHAIRMAN SKILLMAN: Ladies and gentlemen, let me request your indulgence for a second. I've asked Jody to come back to the microphone, Jody Farhat from the Corps of Engineers, to put on the record her credentials.

I didn't do that in the beginning, but as I listened to her remarkable presentation I thought it would be valuable for the record for all of us to know and those who would read the record to know her background.

So Jody, may I ask you please to just speak to the members and the attendees of your background, please.

MS. FARHAT: Sure. So I have a Bachelor’s of Science degree in civil engineering from the University of Iowa, and I have worked for the U.S. Army Corps of Engineers my entire career. I have a total of 31 years experience with the Corps of Engineers. Five of that with the Omaha District in hydrology and hydraulics, and the remaining 26 years in the Missouri River Basin Water Management Office.

CHAIRMAN SKILLMAN: And you're a PE in which state, please?

MS. FARHAT: I'm a professional engineer in the state of Nebraska.

CHAIRMAN SKILLMAN: Thank you, Jody.

MS. FARHAT: Thank you.

CHAIRMAN SKILLMAN: With that I call upon our colleagues from OPPD, Lou Cortopassi, and Calhoun to take it from here.

MR. CORTOPASSI: Good morning, ladies and gentlemen. I'm Lou Cortopassi. I'm the site vice president at the Fort Calhoun Station and I'm the chief nuclear officer for the Omaha Public Power

District. I'm an Exelon Generation employee, but I'm actually an officer of both companies.

And I've been on site at Fort Calhoun since January of 2012. I came in with a small team in an advisory role for about eight months and then transitioned to the roles previously mentioned in August of 2012.

We'll talk a little bit more about the leadership team and the interrelationship between Exelon Generation and Omaha Public Power later in the presentation. And I don't know if you wanted any additional credentials above and beyond that, I could certainly do that.

CHAIRMAN SKILLMAN: Sure, go ahead.

MR. CORTOPASSI: I actually started off as a licensed reactor, non-licensed operator, a licensed reactor operator and senior reactor operator at San Onofre Unit 1. I started there in 1983.

I've worked at also at the Institute of Nuclear Power Operations as a senior evaluator. I also have worked on a number different roles in training, operations and plant manager and vice president, everywhere from Millstone to Indian Point to Columbia Generating Station. And before I joined

Exelon in 2011, at the Palo Verde Nuclear Generating Station, also plant manager there for three and a half years. I have a degree in finance from Georgia State. And as I mentioned, a licensed reactor operator, senior reactor operator. I also have a BWR certification from River Bend in my travels.

With me today, John Brandeau. John, why don't you to introduce yourself?

MR. BRANDEAU: I'm John Brandeau. I'm the manager of project management at Fort Calhoun Nuclear Station. I've been with the District for approximately 12 years, and my entire 12 years at the District I've been doing project management. And I was the flooding project manager/incident coordinator during the 2011 flood event and the cleanup.

CHAIRMAN SKILLMAN: Thank you, John.

MR. CORTOPASSI: Yes, I've also got support, Joe Gasper will run the slides. Joe, just briefly, and Joe's up here for a reason also given what he's doing for us on the Fukushima project.

MR. GASPER: I'm Joe Gasper. I'm lead on the Fukushima project. Worked for OPPD from 1974 through 2010. Retired in 2010 and then came on in 2011 to handle the Fukushima project due to other distractions that were occurring at the time, and I'm still the Fukushima technical lead for Fort Calhoun.

CHAIRMAN SKILLMAN: Yes, sir. Thank you.

MR. CORTOPASSI: And I've got support from regulatory assurance as well as Exelon corporate in the audience if we need to call on those individuals.

So I do appreciate the opportunity. Maybe just by means of reference if you look at the slide, nice sunny afternoon, summer day at Fort Calhoun Station. For point of reference that river elevation is probably about 990 feet, which is kind of a normal band I'd say for us for some operations.

That is a little bit on what Jody was talking about in the previous hour. And like I said, we'll touch on a number of aspects of Fort Calhoun plant operations including the flood of 2011 as well the high water event in 2014. So next slide, please.

So from another perspective, we kind of teed up a little bit the special oversight timeline, and so I'll take us through that not only the flood, which from my perspective is as much a catalyst of events as it was a cause. But you'll see several other key items on there that we'll touch on, in some cases which could be presentations in and of themselves.

So really, you know, so I look to you to best take us where you want us to go into greater detail, because there's quite a bit of information to cover over the last three and a half years.

But we'll touch on the electrical bus fire, certainly based on its regulatory significance, and then through the flood recovery confirmatory action letter, ultimately in the Manual Chapter 0350. The timeline will take us through the operating services agreement, and then I'll take us through CAL closure and restart.

There's a couple of supporting actions though that are important. The Fukushima Response project, you know, ties, so I think is germane to what we're discussing today. And then as we got into, really, into the analysis of not only plant culture but plant design basis in particular, there's a couple of items up there that I think are worthy of touching on, discovery items that we resolved or in the process of resolving as a result of our work while the plant was shut down.

We will take us through plant restart and then through this summer's operations which included some good lessons learned that tie to 2011, and we compare and contrast, you know, the river levels and plant response and support in 2014.

And then I'll touch on probably the two biggest drivers right now that we had is we're working through the Manual Chapter 0350 process. That's problem identification and resolution and our longer term commitment on where we're at with our design and licensing basis, control and use.

So a pretty full morning. I always like the pressure of standing between this group and lunchtime. So next slide.

CHAIRMAN SKILLMAN: And I would offer that we're going to have a hard break at 1200 because we have another meeting that is an important meeting, and that meeting will take us from 1200 to 1300. So the hard stop at 12:00 is real.

MR. CORTOPASSI: Okay. We'll be mindful of that, and like I said, we'll take the questions as they come, even if it's going to be later in the presentation. I think that will just facilitate us getting through it.

CHAIRMAN SKILLMAN: Thank you.

MR. CORTOPASSI: -- as efficient as

possible. So this is the sequence of events with the timeline that we're going to look to cover.

And as mentioned, you know, the flood inspection yellow finding actually issued in the plant downgraded from Column 1 to Column 3 in the October 2010 time frame. And even that finding in of itself has seeds back into the 2009 component design basis inspection process.

So about nine months before the plant shutdown, about nine months before the actual flood event in June of 2011, you know, the station had a yellow finding and was taking actions with respects to improving flood mitigation strategies and with respects to the design basis flood.

MEMBER BLEY: Is it possible to give us a little highlight of that? I don't remember that particular yellow finding, what it was.

MR. CORTOPASSI: Yes. John will look to touch on it, Joe also. But the big picture from inspection activities, and we've seen it at other plants unfortunately, industry. Just the station's actual ability, you know, for the timelines and with the materials on site to be able to protect the station to the design basis level was certainly called into question and challenged.

MEMBER BLEY: Okay, thanks.

MR. CORTOPASSI: And challenged appropriately. The plant did shut down in April 2011 for a refuel outage, and then like I said, we'll talk through what the flood, you know, in the rising river water levels in the June time frame the plant stayed shut down with the cavity full and the fuel in the reactor vessel at that time was the best option for where the station was at.

But you can see across 2011, a series of other significant regulatory findings in the security area. The electrical bus fire as Mr. Vegel mentioned that ultimately resulted in a red finding in early 2012.

The unusual event in June 2011, a white RPS contactor finding in July of 2011. And then we if we work through both confirmatory action letter and then ultimately in from Column 3 to Column 4 and then in Manual Chapter 0350 in December of 2011.

And then in 2012, which we'll talk about, was primarily a year for the station to build their discovery and recovery plan, and then ultimately the Manual Chapter 0350 checklist that was agreed upon and items worked and inspected across 2012 and 2013.

Restart in December of 2013. And like I said, I'll have a number of touch points in between, you know, initial conditions in June of '11 and ultimate plant restart in December of 2013. Next slide, please.

So we'll spend the next portion just really focusing in on the rising water levels and the plant response. And I'll use Mr. Brandeau, as he mentioned, his incident command lead as well as project lead has probably got the most intimate details for plant conditions as I mentioned. I'm intimate from my discussions with plant employees and other items that we've done, but I arrived at the station in January of 2012.

So unusual event declared in June of 2011 in a seasonal flood rather than runoff flood at the end of the outage as I mentioned, so the unit remained offline with a cavity full reactor vessel head off in fuel on that side. It exceeded the 1,004' shutdown level, crested at 1,007' and the design basis was 1,014'.

And the next slide really shows --

CHAIRMAN SKILLMAN: Fuel on which side,

please?

MR. CORTOPASSI: Say again please. Well, there was fuel on both sides, but the core was reloaded back on the reactor side at the back end of the --

CHAIRMAN SKILLMAN: Okay, thank you.

MR. CORTOPASSI: So this slide really gives the perspective on, you know, level up, and then for this type of release from Gavins Point across the majority of the summer, you know, where level essentially stayed until those release rates were reduced towards the back end of summer and then you can see the reduction.

But the total duration of time in total duration of water event, and again I'll let John talk to the pictures and what that impact looked like, not only from, say, a plant safety standpoint, but certainly from an industrial safety and from just managing the facility with not only getting people in and out each day, but also getting, you know, I'll call it food, clothing and shelter and other aspects of what it took just to maintain the site and maintain the site viable during that time frame. Next slide.

And John, I'll let you kind of talk

through the big picture on the pictures here and then subsequent slides.

MR. BRANDEAU: Yes, I'll give you a little background. As Jody had mentioned in her presentation, this was an expected unexpected event, significantly higher than normal snowpack. Montana got a months' worth or a years' worth of rain in a week. And so the Corps started predicting in May that they would have to release significant amounts of water. A hundred and twenty thousand cubic feet per second was predicted at Gavins Point Dam which then went up to 160,000 feet.

And from the previous slide you saw that it was a gradual increase. They just didn't crank it up to 160,000 feet overnight. At our site that meant about six inches of water a day, six inches every day the water came up.

And one of the difficulties for us is that when you have that volume of water no one can really tell you how high the water will be because it's not surveyed far enough out in the banks.

We actually hired HDR Engineering which is a local firm, and one of the engineers there is Jody's predecessor running the dam structure. So he was a vital ally for us on this in predicting our water levels. His best prediction was 1,008-1/2 feet plus or minus 2.

So we took two fronts here to protect the plant. The first front was to protect for our abnormal operating procedure acts of nature, AOP-01 for us, we put in preinstalled flood gates and we protected the plant structures to protect the health and safety of the public.

That's cooling, raw water, essential service water, what we needed to protect the fuel and keep it cool.

The additional work we did, much of which is shown in these pictures, was preservation of assets. We recognized that this was going to be a long duration event. We had to put in asset protection. We had to enable people to come and operate the plant.

So if you look at the top left picture there, that's about two weeks before the peak water. That was an aerial photo. We actually brought a helicopter in to survey all of the company's power lines, OPPD as a whole.

The small channel in the back in between the trees, that's the normal channel of the Missouri River. It was about three miles wide at Fort Calhoun. Well into our parking lots we lost. All of our lower parking lots were flooded. All of our buildings were inundated except for those that we protected.

The top right photo was a significant challenge for us. That's our security building. We wanted to maintain access for the workers, security, ops and all the normal 24/7 people to get there. So we used a variety of technologies that we were able to put together.

What you see there, all those barriers we put up, we did it in ten days from start to finish.

MEMBER CORRADINI: So just to ask, can you go back to the plot in the last?

MR. BRANDEAU: Yes.

MEMBER CORRADINI: So going above 1,004, when you were saying you did all this, where were you in this water level history here?

MR. BRANDEAU: Well, those photos were taken towards the end of June. We had almost, well --

MEMBER CORRADINI: So after you had gotten up to 1,005?

MEMBER JOHNSON: No. We had virtually all of our barriers in place before the river got to 1,004 feet.

MEMBER CORRADINI: Okay.

MR. BRANDEAU: We focused on the, our site, just for kind of reference, the protected area, the majority of the protected area is about 1,004-1/2 feet. That's the vast majority of it. Our training center, 1,008-1/2 feet. Our admin building, 1,007 feet. We have a slight upwards slope.

So we worked from the river out recognizing that the admin building was less important. So we started slightly before Memorial Day and we had the vast majority of our barriers in position by the 10th of June. We were still putting some final touches and figuring out how to maintain it.

MEMBER CORRADINI: But just in terms of so there was an expectation you'd have to do this anyway if you had some sort of an event that started creeping above the 1,004 mark?

MR. BRANDEAU: Yes.

MEMBER CORRADINI: Okay.

MR. BRANDEAU: Yes. It became very clear when the Corps announced that we would have 160,000 cubic feet per second. Remember, that's out of the dam. It does not include any rain or runoff. So it was clear to us that the site was going to be inundated.

MEMBER CORRADINI: Okay, that's what I was --

MEMBER BLEY: It was clear quite a few, three or four weeks ahead of time.

MR. BRANDEAU: Pretty much the last week of May was when we pretty much figured out that we had a problem. I mean we looked at all the Corps information, but it was really towards the last of May that, no kidding, this is going to happen. Next slide. We'll go back to this.

MEMBER RICCARDELLA: These pictures you said were before the peak or after the peak?

MR. BRANDEAU: The photographs, that aerial photograph was taken about two weeks before the peak. Yes. So what happened is --

MEMBER RICCARDELLA: It happened in June didn't it?

MR. BRANDEAU: Yes, those photos, the actual peak was on June 25th by my recollection, and I think those photos were taken on 6/14.

MEMBER RICCARDELLA: Okay.

MR. BRANDEAU: So what happened, and you see it on the peak, is they got the dams to 160,000 cubic feet and kept them there, but then there was some rain and we had a little bit of a peak and then as the rain went off we leveled out and kind of hung where we sat the rest of the year, or the summer.

MEMBER STETKAR: Just out of curiosity, you said one of your biggest challenges was protecting the security building. If I look at the photographs, on the larger photograph in the upper left hand corner, the security building is that little island to what would be the northeast corner of what looks like the footprint of the plant, right?

MR. BRANDEAU: That's correct. Yes, it's on the upper right.

MEMBER STETKAR: It's right along the riverbank.

MR. BRANDEAU: Absolutely. When we put those HESCO barriers in, we were driving Bobcats in six inches of water and having to put in gravel so they wouldn't sink into the sand.

MEMBER STETKAR: Is that a new security building?

MR. BRANDEAU: It is not a new security building.

MR. CORTOPASSI: We're actually in the process right now of building a newer security building. It'll go opposite corner, opposite corner away from the river away from the plant up above --

MEMBER STETKAR: Just say higher ground?

MR. CORTOPASSI: Yes, higher ground also.

MR. BRANDEAU: So our first challenge on this evolution was we did not have an accurate site map of all of our elevations. Our previous flood analysis had focused solely on the protected area, we didn't really know where everything else was.

So the first thing we did is we brought an engineering firm in with a telepole and we walked around with a big overhead photograph and said take a sounding here and here and here, and from that we determined our protection strategy.

As a couple of points, we put all these barriers in. We never lost a day of training in our training center. We were able to protect the training center and its chiller. We put both the training and the admin, our training center, we put them on overhead power. We pulled in our, OPPD brought in storm restoration poles and we transferred them to overhead power.

So I came to work every day. We outsourced a lot of our people. We sent engineering off. We got other buildings, other OPPD buildings plus some leased spaces, but we never missed a day of training.

MEMBER BLEY: John, there's kind of straight, white things around the power block. Is that those blow-up barriers you had installed?

MR. BRANDEAU: No, in the bottom right -- oh, the straight white things --

MEMBER BLEY: In the upper left, yes.

MR. BRANDEAU: Yes. Those are security barriers. On the bottom right you see a closeup of a security barrier with the water running through it. Those were preexisting. They actually made pretty good walkways.

You see we've got yellow lines painted on them? We actually walked on top of those to get through the flood waters. At the peak we had three quarters of a mile of elevated walkways in between the various facilities. So you could go feet dry the entire plant from buildings. You'd basically hop from island to island.

In the top right photograph that shows two of the technologies we used. Underneath those white, the HESCO barriers, which are basically kind of folding out cages with some green material in them, and we basically, they go up very quickly. You fill them with sand and we wrapped them with that white waterproof material. So those are eight feet high.

And then at the bottom of that photograph you see actually there's a trademark Aqua Dam, is a rubber-filled bladder. And we had 2,000 feet of that in the protected area alone and that gave us essentially a moat. We could come over bridges and then we could walk around inside to keep our feet dry.

MEMBER BLEY: You may talk about it elsewhere, I remember hearing that some of that got punctured.

MR. BRANDEAU: Yes, we will talk to that. Next slide, please. Just another views. That is our intake structure in the top two photographs, two different photos of it. The intake structure was outside the footprint of the Aqua Dam and it was protected by installed barriers.

Following the yellow finding for the flood inspection, we implemented a new style of barriers. Our old plan had been to sandbag the doors and it became clear that that's not a feasible option. So we made engineered steel barriers and they bolt right to the building with gaskets. So that building is flood rated up to 1,014 feet.

MEMBER BLEY: But this was only in place a few months before you --

MR. BRANDEAU: That's correct. These had just been designed and tested the previous fall, so this was the first time we used them.

MEMBER BLEY: Did those gaskets, did joints hold?

MR. BRANDEAU: Yes, they held very well. With any of these barriers nothing is watertight. There's always seepage and leakage and you have to deal with that. But it knocks out 95 percent of it.

MEMBER BLEY: Thank you.

MR. BRANDEAU: So that shows some of the features that we had to put in to maintain access. The barriers cover the doorways. You basically see over here, there's a two foot gap in the air.

So we had to build the steel bridge so that the operators could climb up, scamper through the two foot gap, and the little white structure you see there, that's for the security post. That's where the security officer sat out for three months because he had to control access.

In the bottom photograph, that's exactly where the Aqua Dam got punctured. So what you're seeing here is you're looking towards the river from inside of our protected area. You can see the river's high on the outside of the Aqua Dam, very little water on the inside.

That pile of dirt at the bottom there, that was what our crew was attempting to move in the middle of the night when an operator made a human performance error and got into the Aqua Dam with the rear tire of a skid-steer loader puncturing it.

And there are ten sections of Aqua Dam. It looks like one continuous piece but it's really ten sections stitched together. He took the one keystone section out, and then as it failed it dragged the others with it and we had total failure within about 20 minutes of that dam. We replaced it within two weeks. We floated a new one in and reestablished the barrier.

So the water that got on to the power

plant structures, this was a secondary barrier which was not included in our flood procedures. The primary barriers, which we had installed per our procedures, they all held and performed as designed. So we had lost a redundant feature which we then reinstalled.

MEMBER BROWN: So on the right hand side you had other, that's towards the right hand side of that picture is where you --

MR. BRANDEAU: That's correct. Yes. We had engineered doorways. We had sandbag berms. And all of them held when the water came in.

MEMBER BLEY: But these things are commercially available?

MR. BRANDEAU: They are commercially available. This was the trademark Aqua Dam. Later we'll briefly touch on our 2011 high water event. 2014, excuse me. We used a slightly different version, a newer version. They work very well.

MEMBER BLEY: They sit on flat ground and they're --

MR. BRANDEAU: Yes. They're set on flat ground. The advantage of something like this in a protected area is that you fill them with water. If you have to bring that much sand into the protected area it all has to be searched. Very difficult from a security aspect.

Here, you bring them in, you roll them out. You've got all the water you could ever want. You just hook up pumps and you fill them up. So they worked very well. We total on site had about 6,000 feet of these installed around four various buildings. They worked well. Next slide.

MEMBER SCHULTZ: Those were installed during the event?

MR. BRANDEAU: These were installed prior to.

MEMBER SCHULTZ: Prior to.

MR. BRANDEAU: Yes, as the water was coming up these were installed and then inflated. It turns out that you don't just install these and pump them --

MEMBER SCHULTZ: In a matter of weeks before.

MR. BRANDEAU: Yes. In fact the barrier --

MEMBER SCHULTZ: It was not something that was done in 2010 in anticipation?

MR. BRANDEAU: No, no. Absolutely not.

This was all new technology, we found it online. We called the company. We bought everything they had, and they shipped it all to our site and then we figured out how to install it.

MR. CORTOPASSI: Yes, but as John mentioned, and we'll talk. We'll talk some, you know, a lot of lessons learned from this not only for us but for the industry. But in 2014, it didn't have to go to this level, but, you know, how quickly we can go protect the station, you know, at first to 1,004 as well as the other critical junctures that the station can move pretty quick.

MEMBER BLEY: Any idea if this kind of stuff's in that national regional center for storing emergency equipment?

MR. GASPER: No. This, I think all the plans right now, well, the national regional centers are really for the FLEX response which is up to your current design basis flood.

MEMBER BLEY: Okay.

MR. GASPER: So that's all really power restoration, water feeds.

MR. BRANDEAU: For a design basis event, this kind of technology is not really feasible. The water comes up too fast, it's too high and these would be inundated. For this particular event where we had a slow gradual predictable rise these worked very good for us.

MEMBER CORRADINI: Just can I repeat what you're saying? So the assumption in the design basically then is you can't respond because it happens too quickly.

MR. BRANDEAU: You cannot respond to protect non-vital assets. Our procedures have us protect the things that we need to protect to protect the health and safety of the public. There are, water comes up, water comes down quickly.

For something like this we focused much of our effort after we got those protected on asset protection so that we could restart the plant so the crews could come to work so we could continue training so we wouldn't have significant economic impact.

MR. CORTOPASSI: Yes, just maybe a matter of perspective, if you look at the intake building, you know, facing us this way, the grading that you see, you know, above the fire piping, above that kind of middle two thirds of the building is essentially 1,014'. And as John mentioned, the Aqua Dam from an asset protection standpoint, you know, certainly get up to 1,007', maybe a 1,008', but we wouldn't put a dam up that high.

And as he mentioned, on the inboard side then of that Aqua Dam we've got, you know, similar engineered protection for, you know, where's there's diesel generators, an aux building or other critical parts of the station for safety's standpoint.

MR. BRANDEAU: Let's go to the next slide. I think there's some other photos. On the top left, that's a photograph taken from our containment roof showing our administration building. In the right there you can barely see the training center.

Between that white line that you see, which is our security barriers, that's normally a parking lot. Where that tree is, that water's five feet deep. And it was that way for the entire summer.

On the bottom right is the earthen berm that we built around our switchyard. We basically got fortunate in that a hillside we have is a loess clay which suits itself well to building a berm. So in about four days, we mobilized a local construction company. Six road graders ran all day long during daylight for three days while we built that up, and then we put some additional buttressing on it and faced it.

And you can see in that photograph where the river's high on the outside and the switchyard is dry. We did that primarily for continuity of power. That gives us additional backup. We wanted to maintain offsite power available as much as possible so we would not have to use our emergency diesels. Next slide.

MR. CORTOPASSI: All right, as I mentioned at the outset, the flood, you know, certainly a significant event for the station, but when we take it in the total context of the regulatory landscape it was one of a number of issues.

The yellow finding already on the books, you know, station taking actions as a result of it. But in parallel at the same time, a electrical bus fire that happened in June 2011 not related to the fire, and I'll talk a little bit more about it on the next slide.

But also a reactor protection M2 contactor failure, which is equivalent, I'll say to a reactor trip breaker device that the station had done, I'll say insufficient troubleshooting and maintenance and on, and that resulted in a white finding that was applied also in that same time frame, in the July time frame. And we'll talk, the electrical bus. No, we'll go to the next slide, Joe.

So with respect to the electrical bus in the same time frame with flood waters increasing, but if we looked at, you know, the design change that was done to the switchgear in a previous refueling outage, really a combination of insufficient oversight of that design change, insufficient implementation where the actual fingers of the bus work in the bus itself, insufficient engagement in overlap of silver plating, as well as just looking at the differences in the tolerances of the new switchgear as well as oversight of the implementation in post maintenance testing.

A number of issues that resulted in not only the fire occurring but in one case for the fire jumping to the opposite train which certainly elevated the risk significance of that issue.

And there was indications on the site at that time of an acrid odor in the switchgear rooms that in part was attributed to some of the other systems in support. For example, portable diesel generators that were on site creating smoke. But there was certainly opportunities for us as a station to identify that before the event happened.

MEMBER BLEY: Was arcing in there?

MR. CORTOPASSI: Pardon?

MEMBER BLEY: This was an arc fire?

MR. CORTOPASSI: Yes. This was a significant flashover, and as you can see the damage to the cubicle where the source of it was. And that resulted in a declaration of an alert as well as a significant amount of work and investigation into the whys, not only from a technical standpoint but as one of the drivers of the station going into Column 4 and then ultimately Manual Chapter 0350, a good input into what we looked at from a safety culture standpoint.

MR. BRANDEAU: Of note, this happened essentially during the flood. We had already declared the notice of unusual event, and so that added a little challenge to the restoration of this in that we had to bring in all the repair stuff over the Aqua Dams and through the floodwaters to get it there.

MEMBER STETKAR: I read a little bit about the fire but not a lot. You mentioned that it affected the other train? Was that through cables or was it through --

MR. CORTOPASSI: What we found is the interlocks and the wiring for the interlocks in particular on this train, there was one wire that was landed, I'll say, one terminal off. And that affected, I'll use the term "zone select interlock." It affected one of the tie breaks. It affected one of the breakers that should have tripped as a result of the fault. It didn't trip.

And that piece in particular we found, you know, during our retesting during our investigation into the event as I mentioned that is something that should have been picked up in the post maintenance testing when the modification was done.

MR. GASPER: Yes, it was in the as-delivered device, so it was not a landing we made. It was in the as-delivered device.

MEMBER STETKAR: Just didn't do the right testing to --

MR. CORTOPASSI: Yes. So it certainly should have been picked up to the quality at the vendor at the manufacturer and certainly on the receipt inspection. So missed opportunities across for it to get installed in the plant that way and then ultimately not be there when it was required to be called on.

MEMBER SCHULTZ: So Lou, what was the time frame in which you indicate that there was opportunity to pick up the problems associated with the switchgear?

MR. CORTOPASSI: Yes, well, certainly throughout the installation, but in the days preceding the actual arc event there was acrid odors and reports of acrid odors in the switchgear room by operators and others that were not sufficiently followed up on, I'll use that term, and not detected through, you know, the other means, through thermography or other means which you can locate such a --

CHAIRMAN SKILLMAN: So that was in the spring of 2011?

MR. CORTOPASSI: It was right on top of that, that June 2011 time frame.

MR. BRANDEAU: It was approximately two days before the fire where they had started to smell some unusual odor.

MEMBER SCHULTZ: It wasn't a long period of time, but nevertheless there was an opportunity to raise a flag.

MR. CORTOPASSI: Yes, absolutely. And

it's one of our corrective actions, you know, just sensitivity to that odor and what we do whether it's a light ballast or, you know, any time an acrid odor shows up on site that's something we train the operators and the maintenance technicians and the security officers for that matter. You know, individuals that are in the plant are very sensitive to that.

MR. CORTOPASSI: Okay, I'm going to jump back a little bit into the summer time frame. And the floodwaters recede in the August time frame. You know, the first flood recovery confirmatory action letter as I mentioned in the September 2011 time frame, but shortly followed after that with the station moving into Column 4 and then rounding up December of 2011 with the plant being in Manual Chapter 0350.

But an important part of our commitments, you know, for recovery of the station, we'll touch the next slide, we had an entire subset of just flood recovery action plans.

And that was everything from being able to look at each system and whether it was touched or not touched by the flood, what the impact was. Recovery of emergency planning infrastructure, recovery of security infrastructure. But a very detailed recovery plan for the station both from a safety standpoint as well as from an infrastructure standpoint.

As John mentioned, you can look at that security building, and we saw the same in 2014, you know, we're moving fencing, we're moving intrusion detection. We're moving a lot of the infrastructure for us to be able to adequately protect the station certainly at the elevations that were seen at the 2011 time frame. So this is an important sub-piece of what we did.

But I'm going to go back to, later in the presentation, as we really got into the details of understanding, you know, the culture and the performance of the station, the flood recovery was an important, but I'll say a small part of work that we've done over the last couple years.

MEMBER SCHULTZ: The time frame of this recovery action plan, when were those developed? I presume as the flood receded, but just to be particular what was the time frame for the development of these 17 --

MR. CORTOPASSI: Primarily 2011. And then as we got into 2012 we docketed this as part of our recovery plan to the NRC. But an important subsection of these actions, I'd say the majority.

MEMBER SCHULTZ: All the way through December?

MR. BRANDEAU: That's correct, yes.

MR. CORTOPASSI: When I arrived at the station in January 2012 we made some minor adjustments. But for the most part actively pursuing the restoration of the site at that time.

MEMBER REMPE: Do you have any idea of the cost of this flooding event with respect to down time plus the recovery?

MR. CORTOPASSI: I'll talk total cost and then this one gets interesting because we actually filed an insurance claim on this, right, based on extending its impact on the site, number one, and then extending the outage. So total cost right now of the station recovery is about $190 million.

MEMBER CORRADINI: Just the station?

MR. CORTOPASSI: The station costs over the time frame of recovery. And there's recovery costs that we're incurring as we speak now, and we'll talk later about some post restart commitments and some that are fairly significant. If you look at the flood insurance claim that was specifically made, in the $30-$40 million range.

MEMBER REMPE: Okay. So at this high water event that occurred in 2014 and knowing what it takes to implement all these measures, is that the best, I mean thankfully your guys taking all this water at the station protected perhaps the folks in Kansas City or something like that, and so is there not a better way to improve the infrastructure so that you don't have to deal with this? Has that been discussed at all?

MEMBER CORRADINI: She's being polite.

MR. CORTOPASSI: No, absolutely. One of the things that we are looking at, is there some structures that we would make more permanent, switchyard being a good example. I don't believe we would go down, I'll say, the path cost prohibitive and maybe engineering prohibitive to build a design basis safety related flood barrier for the station.

MEMBER REMPE: Maybe it's not your responsibility. Maybe it's something that the U.S. government says should, I mean that's what I'm going to and I tried to ask that earlier with the Army Corps of Engineers. That maybe it's their responsibility too. But it just seems like there ought to be a higher level, like we need to deal with this in a different way.

MEMBER CORRADINI: So to ask the question differently. In this Region, have there been proposals at least floated about additional reservoir needs? Maybe you guys aren't the right ones, but I guess what I'm curious about is, where I think Joy was going was it's not just your problem, it's the whole Missouri River Valley problem.

MR. CORTOPASSI: That's 40 million people roughly.

MEMBER SCHULTZ: The way it was explained is what you need is another river.

MEMBER REMPE: Well, maybe that would be cheaper.

MEMBER SCHULTZ: In 2011 this was --

MEMBER CORRADINI: I mean the question, I guess, what I thought Joy was asking is from the standpoint of the need for, given the variability is there a need for, have there been plans for additional reservoir construction and have just they've been postponed? That's all I was curious about. I think that's where she was going.

(Simultaneous speaking)

MR. BRANDEAU: You know, that would be an an extremely expensive and long term thing to put additional dams upstream.

MR. GASPER: And if you actually look at the amount of surface area on the Missouri that's in dams now, if you look on Jody's graph it's kind of difficult to figure out where you could put another dam even given the slope of the valley.

MEMBER POWERS: Just build a floating nuclear power plant.

MR. CORTOPASSI: The other piece, and I use this illustration with the employees of that, friends and colleagues, if you look at the 2011 time frame we had a design basis earthquake at one of the stations, right.

A design basis essentially off site, loss of offsite power at a large station tornado and while both, as well as another tornado at one of the other stations in the Virginia area. And all significant, but the flood's not what kept us shut down for 900-plus days.

A catalyst without a doubt, but if you

look at the flood waters receding, and still that would be a significant event in and of itself, flood waters receding, going back after the flood recovery and the infrastructure. But it's a catalyst of the other issues that we've worked through at the station, and so it's not what kept us shut down for 900 days.

The items that I touched on, I'll touch on some, but certainly the bus fire as well as others, you know, and then when you stand back and look at the 95003 process at safety culture and beyond, that's what keeps the plant in the configuration it did through December of last year.

MEMBER RICCARDELLA: The $190 million you mentioned includes loss of power generation?

MR. CORTOPASSI: Yes. Yes. It gets a little difficult for me to answer that question because we're very cognizant of what we put in the regulatory accounting process, what's tied to shutdown and what's not tied to the extended shutdown.

And that affords us from a ratepayer standpoint to be able to spread that cost appropriately over ten years as opposed to the ratepayers that happened to exist at the time of the plant's shutdown.

Okay, and so some movement, like I said, broader than flood, you know, as we mentioned and Mr. Vegel had mentioned, remove from the reactor oversight process and place in Manual Chapter 0350 in December of 2011.

We docketed a couple different revisions of our integrated performance and improvement plan between January and June of 2012, and that afforded the road map with which we worked with the oversight panel to say here are the key areas that we're really going to have to go look deeper into or we're going to have to commit to resolving before plant restart.

MEMBER BLEY: Just a point of clarification for me, if you would. I know you said you learned from the reactor oversight process, but in the other process, the 351, still much of the, at least the analysis that supports the reactor oversight process still continues, right?

You all can still get findings and evaluate their risk --

MR. CORTOPASSI: Absolutely. So with the plant not operating so, you know, the performance indicators become for the most part, you know, don't show since we're not an operating facility, but yes, absolutely, findings of significance that will resolve through the process of which we had a number. And I'll talk about a couple of those later.

Okay, Slide 14. In the overall restart checklist I didn't hit every area but I hit really the germane areas that the station used for additional analysis in many cases, you know, physical changes to the plant.

And so Section 1 is really the findings of color that started with 1 alpha which was the yellow finding. I mentioned the reactor contactor failure, 1 bravo. Electrical bus fire, security.

And then safety culture, organizational effectiveness, and then one that was added based on our discovery, another of the discovery items across 2012 and '13 that in retrospect, you know, were reportable and affected the performance indicator for safety system functional failures. And so that was added at a latter point in time.

There was a couple of small additions that were made to the Manual Chapter 0350 checklist. But Section 1 was primarily the resolution of either colored findings or in one case a colored performance indicator.

And then Section 2 really got more into, I'll call it plant systems. And I've touched on a few and I'll touch on a few additional. But flood recovery being the main thing, system health, which is water system health as well as impact of all of the systems as a result of the flood.

Flood impact on soils and structures with one item in particular that was discovered during, I'll say the back end of the flood waters, is the turbine building sump.

The drain lines for the turbine building go beneath the foundation of the building actually into the soil, and the operators were noting, I'll say dirty or sandy water that was coming into the sump which was indicative of water seeping through cracked pipes down below.

So there was concern about underneath the facility, you know, what might be occurring. Not so much the turbine building, but we did extensive studies below the auxiliary building below the containment to ensure that there was, this is my technical term, negatively affected soil beneath those structures.

So a lot of work that we did with the

geological firms to ensure, one, that we didn't have any additional issues and then, two, repair the piping underneath the turbine building.

Containment penetrations I'll talk about, containment internal structures I'll also talk about later in the presentation over physical changes that either have been or will be made to the plant.

And then Section 3 was primarily, I'll say different processes. Everything from the corrective action program to a couple of other items that we had discovered or based on our analysis of station performance we wanted to make sure were in good shape or in good condition before we would advocate a restart of the plant. And that's everything from our safety related parts program to our equipment qualification. Vendor modifications, as I mentioned, the bus fire, red finding. Very significant from how we were managing vendor modifications.

10 CFR 50.59, I won't read them all to you, but primarily split between Section 1, findings of color, Section 2, physical plant, and Section 3, programs.

CHAIRMAN SKILLMAN: Programs.

MR. CORTOPASSI: Yes.

MEMBER BLEY: Lou, can you expand a little bit on, I'd call it corrective action program but it also, you know, the concepts are linked with the post maintenance, post installation testing kind of thing. Have you changed how things get inserted into that, how they get tracked?

MR. CORTOPASSI: Yes, absolutely. Yes, so wholesale changes to process, but as we have found, and I'll talk a little bit about, really, the major remaining item that we've got with the Manual Chapter 0350 panel, it's aligning the behaviors and leadership oversight, aligned with them.

I mean our process wise, and I'll talk a little bit about integration in the Exelon fleet. Process wise, you know, pretty close in this industry, you know, whether it's the software platform that you're using or the procedures or how you work through corrective actions day and day out, but really does come down to the individual behaviors whether it's the engineer, you know, the operator, how the shift manager does initial triage of an operability determination, and that's really what the drive has been.

We did tighten up the process to make it look like the rest of the Exelon fleet which the net facilitates the same performance indicators and makes it easier to detect where we're having issues. But those process changes, I'll say were just this part of what we've done and that behavioral piece is the majority, whether I'm talking corrective action program, human performance, industrial safety.

MEMBER BLEY: How do you measure how you're doing on that one?

MR. CORTOPASSI: Pardon?

MEMBER BLEY: How do you determine how you're doing on that?

MR. CORTOPASSI: We've got metrics down and certainly down to the department level where we can see where we either need additional oversight or not getting the performance we expect.

And if you look at it, I'll talk a little bit, you know, in aggregate what it took, and you'll see a pretty impressive number of just, you know, number of root causes, number of apparent causes over the discovery and recovery phase.

What we're essentially back down to what I would call a balanced or normal baseline number of inputs. A little bit higher than some of the single unit sites but at least, you know, and so now it's managing the backlogs that we pushed post restart to make sure that we're not missing something and that we're effectively going at those in a timely manner.

But you'll see a very significant bow wave of corrective actions across the 2012 and '13 time frame.

MEMBER BLEY: Okay.

CHAIRMAN SKILLMAN: Lou, I'm surprised that work management didn't pop out on this list. So I'm curious where work management fits.

MR. CORTOPASSI: So what we, as also as part of being in Manual Chapter 0350, we did use the 95003 process which went and identified our fundamental performance deficiencies.

And then we looked at each of those fundamental performance deficiencies and said what's a pre- and what's a post restart item on there. Operational focus was one of our fundamental performance deficiencies which ties right into the work management process.

And you'll see between that and equipment reliability strong ties into what we've done both pre- and post-restart from a work management standpoint.

But that section of analysis, and these are all hard restart items for us.

If you look at the 95003 process, you know, it's designed to be able to be done with a plant that's operating. We did it as part of the shutdown process because we believed, one, that's what drove our safety culture, that's what drove a lot of our other corrective actions.

But as part of that analysis using the 95003 process is where we flushed out those items which would include driving the work management process.

CHAIRMAN SKILLMAN: Thank you.

MEMBER SCHULTZ: Lou, one more question along the same type of lines. In 3 alpha you've got corrective action program and then identification of performance deficiencies.

When I looked through the materials prior to the meeting I was looking for elements associated with the extent of condition investigations. Is that something that you look at across the board or is that focused in those two elements of your program?

MR. CORTOPASSI: It will get each time for each of these items, for example, a minimum of one and sometimes multiple root cause analysis. So that would look, you know, specifically at these line items at extent of condition.

And then we did a couple of items on the back end just looking for a common factors across all of these different areas. For example, you mentioned work management. We didn't come up with a specific fundamental performance deficiency on training, yet we knew looking at the corrective actions not necessarily to prevent recurrence but there's a training element on 50.59.

There's a training element on CAP. There's a training element on operability determinations. There's a training element on design and a lot of focus on the design and licensing basis.

So we did it from a couple of perspectives, I'll say at the line item level, and then standing back and looking in aggregate at common factors to make sure we weren't missing, you know, another area just based on how we bend corrective actions. Because as you'll see in an incoming slide, 70-plus root causes over the time frame is a pretty rich data set to be able to draw some other inferences or other conclusions from.

MEMBER SCHULTZ: And all of those programmatic elements that you just mentioned are focused also on the general issue of safety culture and overall performance management.

MR. CORTOPASSI: Yes, absolutely. So we looked at really, you know, the overarching causes for performance decline. Safety culture, subset safety conscious work environment.

And I've done, I'll say a fair amount of work in the Northeast in the '90s and after 9/11 and had pretty good experience on safety culture in that part of the country. Similarities, but different, in my mind.

More of, you know, station, I'll say overwhelmed and in some case given up, which is different than what I've seen in my past. No less significant from being able to find and fix our own issues.

So we went after, you know, safety culture, safety conscious work environment, corrective action program and nuclear oversight pretty early on as the overarching causes for performance decline that tie a lot into the other areas that we're looking at, or that we ended up looking at.

Okay, I'm going to take us now into still in the 2012 time frame. The operating services agreement with Exelon was signed in August of 2012, and that does extend through 2033, for all intents, to the end of the current operating license.

By Nebraska law we're only allowed to sign for 20 years and so there's a little bit of overlap on the back end that my successors in the 2025 to '33 time frame will deal with. But for all intents, you know, the plant is, you know, with the Exelon support throughout the end of the plant life.

MEMBER CORRADINI: Maybe you said it. 2033 is the end of the current license?

MR. CORTOPASSI: Yes, while shut down we entered the period of extended operation.

MEMBER CORRADINI: Okay, that's what I wanted to ask. Okay.

MR. CORTOPASSI: August of '13 and then, yes, a little bit longer. There's probably some value at a later date of looking at recovering the lost time when the plant was down, but right now the current license through 2033.

Just real briefly on the Exelon nuclear management model. For myself, and currently I've got

11 additional managers on site, but it really is a blended leadership team between the Omaha Public Power District and the fleet.

As I mentioned, I had the onsite fleet support but it's really as much the offsite governance oversight, you know, support and performance functions that I receive on a daily basis and sometimes more frequent than that from the Exelon fleet.

So we're parallel with two of the Midwest stations right now through a senior vice president up through the chief operating officer and ultimately to the chief nuclear officer. But, for example, on any given week I've got a number of individuals at the Byron Station, one of our top outage performers. I've got operations and outage individuals there this week.

And then on the other side I've got support onsite, support and regulatory recovery actions that we're doing. But just a significant amount of support and, you know, a change on mindset for how the station is operated with about 85 percent through integration activities.

It's a very detailed, you know, 12,000-plus scheduled. There's items that we pulled forward last year to support restart and just actively pursuing, I'll say the remaining infrastructure. As I mentioned it's lining up the behaviors and the leadership with that infrastructure is what the key driver is right now.

MEMBER BLEY: What is the relationship? You said you're an officer of both Exelon and OPPD. Are the people in the plant OPPD people or is there a mix?

MR. CORTOPASSI: Yes. OPPD is the license holder, so I've got roughly 600-plus total individuals on site, 12 of which are full time Exelon employees.

MEMBER BLEY: So it's not an Exelon plant.

MR. CORTOPASSI: That is correct.

MEMBER BLEY: Is this the first case like that?

MR. CORTOPASSI: No, Cooper has a similar arrangement with Entergy.

MEMBER CORRADINI: And didn't in a prior, maybe I'm getting confused. Not PSE&G, but didn't Exelon also operate some plants in the East in a similar manner?

MR. CORTOPASSI: Yes, the start of a merger of that did not ultimately go through, but had Exelon individuals at Salem-Hope Creek during that time frame.

MEMBER CORRADINI: That's what I thought, okay.

MR. CORTOPASSI: But the merger --

MEMBER CORRADINI: But a similar arrangement in terms of operation?

MR. CORTOPASSI: That would have been different with the merger, and I've used the Constellation Group right now which, you know, Constellation merged with Exelon and we're in the process right now of integrating Calvert Cliffs, Nine Mile Point and Ginna.

And that would have been the same similar for PSE&G because that would have been a merger of companies as opposed to an owner/operator type arrangement.

MEMBER RICCARDELLA: So they would become employees, Exelon employees.

MR. CORTOPASSI: Yes, that's what the Constellation employees are actively being integrated into, not only into the fleet but also as Exelon Generation employees.

MEMBER RICCARDELLA: Thank you.

MR. CORTOPASSI: Yes, and that arrangement is very crystal clear from the OPPD is the license holder. And I'm kind of the lone person in a unique position. By contract mine is the only position that has to stay as an Exelon employee.

And as we're very actively developing the public power employees, for example, we just promoted one of the shift managers to outage manager. He's got a full time, you know, senior leader mentor from the Exelon fleet, but there's good talent on site that we're going to continue to develop not only on site but look for rotational opportunities inside the Exelon fleet.

Okay, next slide. And I'll take us to the end and then we are going to jump back. But we did confirm our readiness for restart in the November of 2013 time frame. The NRC closure of the restart confirmatory action letter, post restart confirmatory action letter that I believe Mr. Vegel may spend a little bit more time on this afternoon on that.

And then authorization to restart the station came on December 17th. We had been holding at normal operating pressure and temperature. We went critical and connected the grid and reached full power on December 26, 2013.

I'm just going to touch a little bit on early operations, then we'll talk about key move to the operations. I believe we just finished the third quarter at midnight last night. But big picture, resume safe operations on, excuse me, critical on the 18th, breakers closed on 21st.

And it was interesting. With the plant having been shut down for, you know, for 900-plus days, we did two heat-ups beforehand. One to do a significant amount of retesting and then the second heat-up in preparations for bringing the unit back.

The station performed very well from, I'll say from a leaks standpoint from the amount of maintenance from the amount of work that we did, you know, both the mechanical as well as electrical work. We had one very small steam leak on one of the pressurizer safety discharge flanges that we went and repaired in between heat-ups.

But other than that for the most part, the overall station performance from an equipment reliability standpoint has been pretty strong. And I'll talk about a couple of the challenges that we've had subsequent to restart. So on January 9th we did have an unplanned shutdown.

And I'm just going to ask you to advance to Slide, Joe, if you just typed in 28 and hit enter that may help us. I'm just going to use this because it's indicative of the issue that we had. And so this is a cross sectional view of our intake structure.

On my far right hand side, the six sluice gates is those kind of a small black triangle. And then above it there's a series of piping and such that's just used for different things inside the plant.

But the bottom line, in the January time frame we were actually operating at a pretty low river level over the last two winters, and about 983 feet is where the level was operating plus we had the extreme cold in the January time frame.

We had a small water leak on that red line right above one of the sluice gates and we ended up with that leak impeding down on the stem on top of the sluice gate with, I'll say a large ball of ice that the operators detected on their rounds on the back shift.

And so our concern was that that sluice gate would not be able to be closed. It's a key part of our flood mitigation strategy. Declared it inoperable, and the operators appropriately removed the unit from line, removed the unit from service.

We closed the sluice gate, did our repairs and a number of corrective actions from a monitoring standpoint. But we did have that unplanned shutdown if you go back to Slide 19, and we'll come back to this drawing for different purposes.

MEMBER BLEY: Take you back to, as you came up in temperature and pressure, how were the steam generators during the almost three years?

MR. CORTOPASSI: Fairly good.

MEMBER BLEY: They were dry the whole time?

MR. CORTOPASSI: No. So the interesting challenge, and I've seen this at other sites. When the station's not sure how long they're going to be shut down, chemistry sometimes takes a back seat.

So there were some challenges during the flood period that how long, you know, what level of lay up should we really be in. So once we got into 2012 and recognized that the plant's going to be down for awhile is when there was more aggressive actions taken across the secondary plant. New steam generators that were installed in the 2006 time frame as part of a large modification at the steam generators pressurizer head, among other things that John was involved in.

And so we saw a decent amount of impact on secondary chemistry, more so when we came online at above 30 percent power. And that was more on the feedwater heater strings, but overall steam generator performance, you know, we were able to clean up fairly well beforehand. But we saw, like I said, the heater strings just couldn't get all of that stuff with the flushing strategies that we used.

And we've done quite a bit of benchmarking between San Onofre and Crystal River and other plants on their shutdown chemistry strategy. But historically the station, and it's really a testament to a lot of infrastructure that's been invested, is a top decile chemistry performer. So we look forward to, I'll say a normal refuel outage and normal cleanup cycle coming out of next outage.

Okay, so I mentioned the forced outage to repair the river sluice gate, and then on plant restart we did have a control rod issue right after the reactor went critical.

And again operators appropriately shut the unit back down. And those were two of seven more significant issues that we had early on in plant operations.

It's interesting though. A lot of discussions with Mr. Vegel and even in the public setting, you know, about the operators after 900-plus days, one having the right operational tension, operational mindset. And we use the term are the operators going to make the right decision at 3 o'clock in the morning?

And, you know, lo and behold, the reactor shut down on January 9th. We got off line at 9 o'clock in the morning. That started at a little after 3:00 in the morning, and you can see the time frame from the CEAs. Both back shift issues, both good conservative operations and identification by the shift manager to put the plant in the configuration that we'd expect.

MEMBER BLEY: Did you retain most of your operators during the outage?

MR. CORTOPASSI: Yes, for the most part. For the most part. You know, a fair amount of turnover just on the site, more so in engineering and in the maintenance shops that I would look at over the last five years. But for the most part retention.

You know, we're seeing a little bit of a bow wave right now with the licensed operators but nothing significant. And I'll tell you, I've done a fair amount of recovery work in my time.

You know, one of the things that we didn't have to, I'll say I didn't have to put additional folks on is the operator pipeline. And so six shifts of operators continued to hire non-licensed operators and licensed operator classes throughout the extended shutdown, which is a testament again to the investment on the peoples' side.

MEMBER SCHULTZ: Because you indicated it was indicative of operator performance, what was the issue with regard to the CEA?

MR. CORTOPASSI: Had a little bit different kind of CEAs in this style of plant. So the operators had taken the reactor critical and were at the step where they were going to reinsert control rods to establish stable conditions and take criticality data and had a failed CEA that wouldn't insert.

MEMBER SCHULTZ: So it made sense to do what they did.

MR. CORTOPASSI: Absolutely.

MEMBER SCHULTZ: Was it a mechanism problem or a fuel problem?

MR. CORTOPASSI: Electronics. Electronics issue, aging electronics issue.

MEMBER SCHULTZ: Okay, thank you.

MR. CORTOPASSI: Okay, our next slide takes us pretty much up to date. You know, I mentioned the two issues we had in January. We had one other automatic scram in the March time frame on our static water cooling system.

And really the focus with the station again sort of from a work management standpoint is really the transition to online operations and management of online risk. You know, with the Exelon processes and oversight, a strong focus on summer reliability, you know, other than, which we'll talk about in a bit, the down power we had to support the rising or the high water level event in June, overall station performance has been good. Not excellent, but has been good from an equipment reliability standpoint.

But we're just in the phases right now of really establishing, you know, process wise and asset management wise how we're going to get to the next levels of equipment reliability.

Okay, just kind of standing back and looking big picture, there we go. And this kind of takes a look in aggregate of what it took for the extended shutdown, and I won't hit all of them.

We touched on the 20-year operating agreement, the 450 restart checklist items that were closed. And all that I'm confident, and it's both from what we've seen internally and what we get fed back externally, we've developed some pretty unique safety culture mechanisms that we use both statistically as well as just design interfaces that we have with the station to ensure that as we're making change and a significant amount of change that we're not doing it at the expense of safety culture. Next slide.

Again the details that touch on, you know, you look at the number of radiography exams, there's a fair amount of piping replacement on our chemical volume control systems, steam generator blowdown system. Next slide.

CHAIRMAN SKILLMAN: That 180 rem, that is for the full duration of this campaign?

MR. CORTOPASSI: Whole duration.

CHAIRMAN SKILLMAN: Thank you.

MR. CORTOPASSI: And then from a corrective action program standpoint, as I mentioned, you know, a significant amount of, I'll say on the paper side from everything from the, you know, root causes to apparent causes to just volume of the corrective action program to drive through resolution of the issues.

All right. I was going to change gears. And again, we talk about this other significant items on site that, one, may be of interest and, two, how it ties in some cases to items that needed to be resolved as part of our discovery activities and as part of the extended shutdown.

So we'll touch on the Fukushima Response Project -- I've got Joe up here -- beyond design basis flood mitigation as well as some things that we've done for normal plant operations. And I wanted to touch on just a couple of the items, tornado-borne missiles, the containment penetrations and internal structures, and also a little bit on security.

Okay, with respects to the Fukushima Response Project, and I guess maybe at this point I'll just as much open it up to Joe that I've got him up here on where we are at.

Big picture on that as well as, you know, we have developed our, right now, beyond design basis flood mitigation strategy while we're waiting to complete our flood hazard reanalysis that is in flight right now in conjunction with NPPD and will be due to the NRC in the spring of next year.

And then really the rest of our commitments still on track are to these specific things on Fukushima Response Project and we may pause for questions.

MR. GASPER: I guess the latest is that we'll screen out based on the seismic reevaluations, so that issue's going to come off our table and planning response obviously is clearly the biggest remaining item we've got to work on.

MR. CORTOPASSI: All right, next slide. As I mentioned, as part of our recovery and part of our commitments. and it's really built on a strategy that was developed in the '90s as a result of the IPEEE work that was done on site, but we have established, I'll say a beyond design basis flood mitigation strategy that takes us significantly above

1,014 right now.

Involves a shutdown included down to the plant and establishment of a secondary heat sink with dedicated materials that are stored above that beyond design basis flood level has been tested. We drove it.

We've got some additional work we're doing this year on preventive maintenance for these items, but a significant investment as we work through ultimately our flood hazard reanalysis work that's going on in parallel right now.

CHAIRMAN SKILLMAN: Lou, did you say this was initiated before the Fukushima activities?

MR. CORTOPASSI: I'll say in parallel and in part in response, you know, to the yellow finding, but not a hard tie to the yellow finding. But as we looked at the work that Joe's doing with flood hazard reanalysis and the fact that we had a beyond design basis strategy in place, we thought it was a good idea and beyond to optimize that and improve that strategy.

Some of it may be transferable to the work that Joe's completing that once we ultimately agree on what the beyond design basis elevation is there's work that we know we're ultimately going to have to do anyways and equipment that we think will be transferable for at least in part for some of the strategies.

CHAIRMAN SKILLMAN: Does this affect what will be your potential demand for FLEX help?

MR. GASPER: No. It does not affect the, we developed the fundamental FLEX strategy somewhat ahead of developing this strategy so that they are integrated together. And ultimately there will be an integration of the final flood response strategy.

So anticipate being able to use, we bought this equipment pretty much that we should be able to use this same identical equipment in the FLEX response. And this equipment's housed at the 1,036 level of the plant. It'll be operated at the 1,036 level if it ever happens.

CHAIRMAN SKILLMAN: Thank you.

MEMBER STETKAR: Joe or Lou, you said you drilled on this. Does it actually work?

MR. GASPER: Yes, we've --

MEMBER STETKAR: Hooked it up and it'll pump water and that sort of thing?

MR. GASPER: Yes. It was fully aligned at a manufactured site. All the --

MEMBER STETKAR: Well, but your circuit breaker was too. I mean at the plant. Have you actually drilled with real operators and people who hooked this up and confirmed that it'll deliver electricity and pump water and they know how to do that?

MR. GASPER: Yes, the diesels are staged and hooked up and will run --

MEMBER STETKAR: You're not answering the question.

(Simultaneous speaking)

MEMBER STETKAR: We're not just intentional, but I'm trying to find out whether Omaha Public Power District operations employees have actually laid their hands on this equipment, deployed it, connected it, made sure it generated electricity and pumped water from point A to point B.

MR. CORTOPASSI: All except that last piece about actually pumping water. And we did that as much, you know, table-topped with the groups in a natural run through with --

MEMBER STETKAR: Tabletops are --

MR. CORTOPASSI: Yes, mechanics and operators, it's a combination of the two.

MEMBER STETKAR: Yes, but tabletops are tabletops. I'm trying to find out if people have actually used the equipment, and I found out. Thank you.

MR. GASPER: And the water sources are refueling water tanks so that's what we did not pump water.

MEMBER STETKAR: Okay.

MEMBER SCHULTZ: Lou, with regard to this large issue, it is well connected to the efforts that are coming forward with regard to the Fukushima items for the industry.

What have you done in sharing your experiences and I'm thinking here with regard to mitigation strategies with industry? Because as you said you started this before Fukushima, before FLEX, before other items that have been put into play not only in terms of figuring what could happen next. So you're ahead of the industry here.

And so where the industry is looking, ought to be looking at, protecting against the beyond design events, you and to an extent have been there done that. You were in a position where you didn't know what was going to happen. You experienced it.

So how are you sharing your experiences and these types of corrective actions with the rest of the industry?

MR. CORTOPASSI: Yes, so two phases. Joe, I'll let you talk --

MEMBER SCHULTZ: All with Exelon. That's a big part of the industry.

MR. CORTOPASSI: Yes, so just from the asset protection standpoint that was straight through the INPO IER/SOER process that was flood recovery lessons learned. In fact, John's going to be back down at a plant manager's workshop next week at INPO.

It'll be the second of a series of, you know, even after the fact, talking in part about it as well as a lot of focus just right now also on event leadership, I'll say, for lack of a better term. You know, for the Fukushima response with Joe's very actively involved not only with the industry, but with the fleet which is very regimented, you know, how we're either sharing lessons or what the similarities and differences are between the fleet plans.

And Joe, I'll let you expand on that if you desire.

MR. GASPER: Well, then also we've done

extensive sharing with the USA utilities through, and then they came down and benchmarked what we were doing. So, and then shared out, I've given two or three papers at ANS, various meetings, on what our response has been.

MEMBER SCHULTZ: I appreciate that response. Thank you.

MR. CORTOPASSI: The next slide's just again on our beyond design basis, you know, completed the reactor analysis to support what our assumptions are.

And again it's a little establishing shutdown, cooldown, secondary heat sink, in really establishing the safety injection tanks and pressurizer as a source of makeup for the duration of which we'd expect the flood waters to be there and then subsequently subside.

And I do appreciate the question, as again I'll just answer it again directly. Operators have checked fittings, worried about hoses, have done, you know, can I get through this doorway, all that stuff, but physically --

MEMBER STETKAR: Did not try to shut down the plant and cool it down.

MR. CORTOPASSI: Yes, did not shut down and cool the plant with it, absolutely not. As Joe mentioned in part, the water that would be used would be, would answer the --

(Simultaneous speaking)

MR. CORTOPASSI: Okay, next slide. Okay, we touched on this a little bit before, but also as part of our recovery we worked very closely, one, in part in response to violations, but also in an improved intake level control strategy.

And so what was employed in the 2011 time frame is those six sluice gates were closed with exception to one that was left partially open, and don't quote me on the distance, but an inch or two open as a means of allowing water to be able to go from the river into the intake structure.

And in the raw water pumps, which is our safety related source of cooling water, they were either, you know, cycled down or off to maintain cell level on the downstream side or on the intake side of the river structure.

So you see 1,014 foot level on the right hand side. Our strategy now at 1,004 feet, if we're going to approach that, we would shut down, cool down and isolate the plant from the river by closing the sluice gates.

And then the throttle valves that we put in place provides much finer level of control for the operators to control intake cell level. And we had done, I'll say a fair amount of testing on that modification. And it's in part one that allows us to close the sluice gates which are not 100 percent leak tight, but we do monitor that.

But the concern with the previous strategy was in part with one sluice gate, you know, partially open. One, it's a huge gate that I'm using for fine level control, number one.

And number two, you know, a particulate or a log or anything else that could get jammed in there that would impact either the ability to move it or the ability to close it. Because, you know, once they get to a certain level in the river the actual motor operated valves are outside, you know, outside the structure itself, they become, you can't get to them. So part of the strategy has us early on divorcing ourselves from the river and providing that finer level of control with the operators that can operate the valves from inside the intake structure.

Okay, as I mentioned, you know, a couple of the other items of significance that I wanted to touch on, and again a lot of work from a flood recovery standpoint, but as we dug deeper into the design and licensing basis of the station, a couple of items in particular, tornado-borne missile protection being one of them as far as what the station was originally licensed to and how over time in some cases components that were moved from inside buildings to outside buildings inappropriately in the 1990s time frame as well as just the overall protection of safety related components that are outside of safety related buildings.

And it's nice to have John again with me on this as the project manager for this. But protection of key equipment, 250 tons of steel. You know, throughout the site you can see some of the bigger structures that we built that protects everything from our steam discharge for our atmospheric and safety relief valves off the steam generators, steam generated auxiliary feedwater pump. These are generator exhausts, a number of just components that we've protected at the station from a tornado-borne missile protection standpoint.

If you hit the next slide you get a kind of perspective of where those major modification took place. Everything from the intake structure on the right hand side across the turbine building, across the auxiliary building, across the fuel building, et cetera.

And John, if you want to touch on anything else on --

CHAIRMAN SKILLMAN: Where are your diesel generator exhausts?

MR. BRANDEAU: When you see the -- and Joe put it right on there, to the left.

MR. CORTOPASSI: To the left a little bit.

MR. BRANDEAU: The red box right there, those are our diesel exhausts. They come up two stacks.

CHAIRMAN SKILLMAN: Thank you.

MR. BRANDEAU: Fort Calhoun's a pre-GDC plant when we were built. The roofs are inadequately thick to withstand a vertical missile. That was a big challenge here. So we're fully compliant with Reg Guide 1.76 now, and the big challenge was protecting vertical missiles.

What you don't see here is the additional challenge of keeping automobiles off the roof. We also have a vehicle exclusion strategy on our hillside where during tornado favorable conditions we have to exclude the automobiles from that area. Because in the Reg Guide it assumes that an automobile within a half mile radius can be picked up 30 feet and then translated the full half mile which would put it on our roof. So that's a secondary part where we manage the traffic on the hillside.

CHAIRMAN SKILLMAN: Okay, thank you. Thank you.

MR. CORTOPASSI: All right, two of the modifications in the work that I wanted to highlight that were discovered during the extended shutdown, one was the containment penetration replacement.

And back in the 1980s it was identified that the original design, not only for ourselves but many other plants, had an inappropriate component in there that was radiation sensitive and would allow that penetration to leak.

And so the station took the tack in the '80s to replace the safety related penetrations from an electrical reliability standpoint not recognizing that it still left the station vulnerable to an issue with the containment integrity. So 363 containment penetrations susceptible to the radiation damage, and spare ones we kept and other ones we procured, real time, and replaced those penetrations.

There's kind of a bingo chart on the right hand side. And you can kind of see, upper left hand side, the amount of intricate work that was done to resolve that issue from a discovery and from a recovery standpoint.

Another, you know, similar and I'll say scope in dollars to the tornado missile work that we did, so another item that we did to improve overall plant safety.

Next item, and it's part of our confirmatory action letter right now, a lot of work and a lot of analytical work on the containment internal structures. And I'm not talking about the outer shell but, you know, the compartments and components and beams that form the inner portion or skeletal structure of the containment.

And we've got two in particular that we will resolve in the next refueling outage, one being the reactor vessel head stand and we'll do that on the front of the others. The confirmatory action letter has us taking that and remediating that fully before we move the reactor vessel head, so that design is in flight right now as far as improving that structure.

And then we've got two beams in particular that support one of our safety injection tanks that we'll be installing three vertical columns, concrete columns, pre-stress them in place, a first of a kind evolution for us.

And so as we've learned in the industry most recently and also working through the institute, again nuclear power operations, this one has a lot of oversight and significance based on its uniqueness with what we're doing in the next refueling outage.

MEMBER STETKAR: What's the concern with the reactor vessel head stand? I mean I understand the safety injection tenets, but --

MR. BRANDEAU: Yes, it doesn't comply with its original design margins. It's a relatively lightweight stand. And to restore it to its design margins we have to put quite a bit of steel in there that will spread the load out over to some adjacent heavier structures.

MEMBER RICCARDELLA: Are seismic loads the problem? I mean is that what the driving force is, the seismic loads?

MR. BRANDEAU: Seismic loads, yes.

MEMBER RICCARDELLA: And then that's what the beams, also the seismic loads?

MR. BRANDEAU: The seismic loads, they're a combination of seismic and some of your accident transients inside where you put loads on the internal compartments, so we have to account for all of them. So we do have projects in place to resolve both of those in the upcoming spring refueling outage.

MR. CORTOPASSI: And they're explicitly called out in the confirmatory action letter. So that's in part why I highlight those.

MEMBER RICCARDELLA: Has your ground motion response spectra gone up as a result of the new --

MR. BRANDEAU: Actually the ground motion response spectra is bounded by the --

MEMBER RICCARDELLA: By the --

MR. BRANDEAU: IPEEE spectra.

MEMBER SCHULTZ: So for you or for the staff, Lou, these were identified as part of the reviews prior to the confirmatory action letter?

MR. CORTOPASSI: Yes. As part of the --

MEMBER SCHULTZ: How was the identification done?

MR. CORTOPASSI: As part of the reviews, you know, as we looked at a number of things under Manual Chapter 0350, this one in particular was looked at -- correct me if I'm wrong, John.

We were looking at an EPU modification that was going to install additional hangers to support component cooling water piping in the containment. And as we dug into the original drawings and original specifications for the containment design is where we found the inadequacy.

So it was found through an EPU look and then extent from that, you know, about how we were going to install additional hangers.

MEMBER SCHULTZ: And the containment penetrations, was that on a work list somewhere or was that something that had been intended to be accomplished but didn't get to it?

MR. CORTOPASSI: I'll have to think about the genesis of how it came in the day we found it, but as we were looking at one of the other items that would probably have been worthy of a slide, and I use the illustration again, you know, what shut you down isn't what keeps you down, right.

The flood being the catalyst, the high energy line break and equipment qualification was another large area and only one of the last areas that we worked through, you know, to say that we were ready for restart.

So that environmental qualification programmatic look is what identified that as well as a number of other modifications that we did for the plant, you know, for steam line breaks. So it's part of the EEQ look and program recovery of that.

CHAIRMAN SKILLMAN: Now the number of items that you've identified and the intents and nature of them kind of makes me wonder how your predecessor signed a 50.54(f) letter back in the '90s. It really kind of raises that whole question.

MR. CORTOPASSI: Yes, so one of the items that we did do as the, what we're using to drive the design and license basis work that we're doing right now is we went back to construction days, and in part even that had a challenge as we changed architect engineers halfway through construction on this site is another unique aspect that was added.

But the station was on the troubled plant list or the equivalent in the late '80s, '90s and went through a lot of, I'll say initial phase of design license recovery at that time. And probably, you know, Joe, you can probably give me more illustration on it. And so a lot of work was done in that time frame, probably comparable or maybe even more so than some of the contemporaries.

And I'm trying to put my 1995 hat on, because looking back, yes, that's a fair challenge, and had those same discussions ourselves as we built the timeline back to construction. And I think it was in part the work that had been done just previous to that is what allowed the station to feel comfortable at that time.

CHAIRMAN SKILLMAN: Thank you.

MR. CORTOPASSI: All right, just going to touch briefly again on the security upgrades, in part, you know, from a flood recovery standpoint and in part just to comply with the security order. But a lot of work that we've done both safety culture wise as well as infrastructure with security.

Okay, I'm going to flash us forward. I did want to touch on the 2014 high water event problem identification and resolution from recent inspection activities, design and licensing basis and then hold to our hard stop at 12 o'clock.

So 2014 high water event. Heavy rainfall downstream of the Gavins Point Dam, I think the technical term is unregulated water when, you know, 10 to 12 inches of rain on the side of Iowa and Minnesota that slopes our direction, and we had at one point a projection of a crest at 1,004 to 1,006 feet.

And so, procedurally, based on all our projections we put the station into action, a very conservative bias to prepare for plant shutdown. And those are pictures from this time frame with actively as, you know, we talked before about what it took in 2011. We activated the site to go protect the station to 1,004 plus feet. Next slide.

So we also reduced reactor power to 30 percent, filled and staged sandbags, the aqua berm and HESCO barrier. We ultimately crested at 1,001 feet, and you can see again some of the additional activities that took place in that time frame.

And John, again, you know, part of the infrastructure, part of the command and control structure. In a relatively short period of time we moved HESCO, we moved sand and we protected the security infrastructure.

Again a lot of communications both with the Region, certainly with the Army Corps and the National Weather Service primarily. And we looked at, again, even some of the tools that we had from 2011 to be able to look at the upstream river markers and correlate it to what we were seeing on the site.

We had very accurate predictions, but again a conservative approach based on potentially what was happening upstream as well as, you know, the National Weather Service in particular had a lot of boots on ground looking at the small tributaries and really what was taking place upstream.

And the Corps reduced flow at Gavins Point essentially to what I'd say is the minimum to help aid in what we saw. But crested at --

CHAIRMAN SKILLMAN: What communication caused that to occur?

MR. CORTOPASSI: Well, essentially when I listened to Jody's presentation this morning, I work from two pieces.

The shift manager's got direct phone lines into the Army Corps, but I work with the environmental leadership downtown at the Omaha Public Power District that has close communications with what's going on river level and the Army Corps on all the phone calls that I was on at least with the National Weather Service and the other, you know, FEMA and the other constituencies in both Iowa and Nebraska that were dealing with it from an infrastructure standpoint.

And so, you know, from essentially day one to where we saw river levels potentially coming up those phone calls started taking place twice a day.

MR. BRANDEAU: Of interest on this based on our 2011 extended flood experience we implemented all new procedures. Where previously we only had procedures for accident and nature, now we have more general guidelines with all the lessons learned for how you protect other things.

That really helped us a lot in this event because we didn't have to refigure it out. We knew exactly where to put our priorities, what we needed to protect and what we didn't need to worry about.

MEMBER SCHULTZ: John, it looks like your sandbag there, or your brother's.

MR. BRANDEAU: There was so many people pulling sandbags. Yes, essentially though you can imagine as the top of the operators, you know, similarities and differences even for this, had we got to 1,004 it would have been relatively up and down.

You know, once the rain stopped it really wasn't a continued flow, but a lot of just, you know, especially as individuals started to see sandbags going up, a good emotional, I'll say emotional discussion with security officers and with the operators and, you know, what's similar and what's different about 2014.

CHAIRMAN SKILLMAN: Do you have a challenge with regard to your work force and union and who's allowed to touch sandbags and who is not allowed to touch sandbags?

MR. BRANDEAU: No. Everybody touches sandbags.

CHAIRMAN SKILLMAN: Thank you.

MR. BRANDEAU: Part of our wellness program.

(Simultaneous speaking)

MR. CORTOPASSI: Absolutely.

MR. BRANDEAU: We did not have those issues.

MR. CORTOPASSI: Absolutely.

CHAIRMAN SKILLMAN: All hands, grab a bag, go.

MR. CORTOPASSI: But I'll tell you that piece, you know, so this is the broader district then who we've got other infrastructure that we're protecting, so we've got the transmission substation individuals that come support and as well as, you know, probably equally important just additional safety advisors. Because it can be, you know, it's got to be a controlled yet expedient evolution. And I've got John and other managers in the field, but we brought a number of safety professionals just in to watch individuals that aren't used to, you know, in some cases doing heavy lifting.

MR. BRANDEAU: In that bottom picture that's actually our transmission and distribution group sent up probably 100 people, 20 trucks, took care of the switchyard for us.

CHAIRMAN SKILLMAN: If this had been part of Thanksgiving or Christmas when your river's running 32 or 35 degrees Fahrenheit would you have a different outcome?

MR. CORTOPASSI: How so?

CHAIRMAN SKILLMAN: Temperature of the water, complications of just dealing in that very cold, very wet environment?

MR. BRANDEAU: I don't think so. I think most people would prefer to do it when it's cold than when it's hot.

CHAIRMAN SKILLMAN: Okay. Fair enough.

MR. BRANDEAU: Always put a sweater on.

CHAIRMAN SKILLMAN: Thank you.

MR. CORTOPASSI: For a challenge though as far as, you know, what I saw, the lessons learned from 2011, and we critiqued after this also to make some additional refinements to the procedure as well as, you know, once you get down to the demobilization, I think, is as much just as equally good lessons learned on that part that we'll use if we need it going forward.

CHAIRMAN SKILLMAN: Okay, thank you.

MR. CORTOPASSI: Okay, the final items I was going to touch on, and I'll know we'll have some discussion from Mr. Vegel and company on where we're at in the 0350 process.

So a couple items that I'm just going to tee up from my perspective, we had a public meeting last week in Omaha that discussed the results of an extended inspection in July of 2014, primarily focusing on problem identification and resolution as well as closure of confirmatory action items.

And overall performance, about 130 of 180 CAL action items closed. Of the ten key driver areas about half were recommended for closure. But that said, the 0350 panel also recommended that we remain in 0350 oversight at least for the time being.

And there's really four criteria that are looked at. Overall conservative bias and operations of the plant, which I think we've demonstrated successfully. Long range improvement plans, which I touched on a little bit today that, you know, our path forward with where we're taking the station, I think we got good feedback on that. Resolution of the issues that got us into Manual Chapter 0350 in the first place. The findings of significance as well as extent of condition, I think we had good performance on that.

So the last area that really came down to the corrective action program were in some cases and in particular in our design engineering area, I believe we still have additional work to do. Not so much in the identification, to a lesser degree in the evaluation, but in the resolution of issues.

And that's what the inspection team had clearly pointed out to us and as a focus area for us at the station primarily in engineering and primarily in the subset of design engineering with some of it being our post restart commitments and actions, but resolution of a number of issues, lower level issues that were identified last year that, you know, we've got an operability space right now but need to be able to demonstrate and show a clear path to full compliance.

And so we'll continue to work with the Region and with the 0350 team on when we would advocate an additional inspection in that subarea.

And like I said, Mr. Vegel, I'm sure, will touch on some of the other areas in the confirmatory action letter. I touched on a few, the contaminated internal structures being one that's longer term will take place over the next two refueling outages.

And then the next slide, probably our largest commitment is the design and licensing basis control and use and reconstitution project that's in flight right now. We're using raw water as a pilot system this year and then we'll go into full production across the remainder of the system starting in 2015 with an expectation that we'll have the commitment closed by fourth quarter of 2018.

CHAIRMAN SKILLMAN: Is the challenge down at design engineering, rigor, maturity, training, background? What's the real issue down there?

MR. CORTOPASSI: Yes, you know, the training component in particular, I think we've rebaselined everybody in how we use the tools, how we process operability in just what good technical rigor looks like.

And so a little bit in the oversight and a little bit in, I'll say in a particular pocket of design engineering. But I'll tell you in part and there's one issue in particular we're working through right now on switchgear ventilation which we've got non-safety related switchgear cooling for our safety related switchgear. Not even original design. Those were even put in after original design.

And so for the most part during recovery, our bias has been to either restore the plant to design or go build margin back in. And we're working through, I just recall some low margin issues right now that, you know, we'll look to just take off the table by putting margin into the plant.

And so it's kind of a soft answer because as we work through we're more interested in having the right level of oversight and right level of just understanding of what it's going to take to get a couple of these issues back into full compliance. And that the engineers clearly know that and can clearly raise their hands when we need additional help on areas that are challenging.

But we expect, you know, it's kind of a prelude, because we expect as we work through the design and licensing basis, you know, reconstitution project, we've got to get good at being able to manage the issues that come out of it, a number of which I think we have discovered and rectified during the extended shutdown, but there's purpose for why we're going after this project.

You know, it kind of goes back to your question about 1995. We got it, you know, might as well get it right.

CHAIRMAN SKILLMAN: Okay, great.

MR. CORTOPASSI: And the very last slide, I'm not going to read back through this. I'd really just open it back up to this group. While you have us up front is there anything else that we can either ask or advocate or provide additional insights? There's a lot of activity over the last couple of years and a lot of activity, you know, coming at us right now.

CHAIRMAN SKILLMAN: Okay, for my colleagues I say thank you, but let me ask my colleagues. Any questions or comments, observations?

One of the purposes for this presentation is to give the members a thick magnifying glass into what happens when you lose your keys and what you have to do to get them back. And as it turns out it's connected with the flooding but not so much.

There were other underlying structural problems, and as Lou has said repeatedly, the flooding from the Missouri was a catalyst to display all these other warts and wrinkles, and this is what it's taken. And you asked the key question, Joy, how much did it cost? It's a big deal.

MR. CORTOPASSI: Absolutely. Absolutely.

CHAIRMAN SKILLMAN: Colleagues, any comments before we break?

I want to make one comment. I want to recognize Mark Banks, his effort to pull many of these pieces together. So Mark, I want to thank you on the record. Thank you.

MR. BANKS: You're welcome.

CHAIRMAN SKILLMAN: And with that we are adjourned until 1300 on that clock. Thank you.

(Whereupon, the above-entitled matter went off the record at 11:54 a.m. and resumed at 1:00 p.m.)

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

(1:00 p.m.)

CHAIRMAN SKILLMAN: Ladies and gentlemen, we're now back in session. And as we begin the afternoon session, I'm going to call on Mike Hay and Tony Vegel to please introduce, or reintroduce themselves, and to proceed from here, please.

MEMBER BLEY: Very good. Thank you very

much. I'm still Tony Vegel, and good afternoon. This afternoon Mike Hay and I will be presenting a more detailed discussion of the Manual Chapter 0350 oversight activities at Fort Calhoun station.

We're going to talk about how we implemented the Manual Chapter, and to get into a little more detail with the number of resources that it took, as well as a little bit more detail on some of the technical issues, and our involvement in the disposition of those issues. And then at the very end we'll talk about the current status of the manual for 0350, and where we see Fort Calhoun station performance.

So, with me is Mike Hay. And for background perspective, I've been with the NRC since 1989. My background before that, I joined the Navy in 1977 as an enlisted man on submarines, and eventually became an officer. And left the Navy and joined the NRC right after that.

And with the Nuclear Regulatory Commission I first started in Region I for a couple of years. Then I was the resident inspector at the Perry plant, the senior resident inspector at the Fermi nuclear plant, and then the last senior resident inspector at the Zion station.

After that I became a branch chief in Region III, responsible for multiple plants, including D.C. Cook, where I had the opportunity to be involved with 0350 activities there. Also led the team for the LaSalle restart inspection. And also, when Point Beach entered Column IV as an action matrix, I led the 95003 inspection there as well.

And then eventually got smart and moved to Texas, and in Arlington, where I've been a division director in the Division of Reactor Projects, in Reactor Safety, and also the Division of Nuclear Materials Safety. And my current position is Director of Division of Reactor Safety. And I'll let Mike Hay introduce himself.

MR. HAY: Good afternoon. My name is Mike Hay. My background is ten years nuclear Navy. I was enlisted, and I was on a submarine, fast attack submarine at Groton. And I was a staff instructor out in Idaho. I have a Bachelors and Masters degree in Health Physics. My Masters is from Texas A&M University.

I joined the NRC in '95 as an HP inspector. So, I did that for a few years. Then I became the resident at Cooper nuclear station when the ROP first started. Cooper was a pilot plant for that initiative. While I was resident at Cooper nuclear station, the station did enter Column IV of the action matrix. As a matter of fact, they were the first plant to enter Column IV in the new oversight process.

I left Cooper and became the senior resident at Waterford nuclear station. As a matter of fact, I was the senior when Hurricane Katrina went through Louisiana. After that I became a branch chief in Region IV. I'm currently on my fifth branch chief assignment.

My assignments have included two in DRP, where I was the branch chief for the boiling water reactors, Grand Gulf, Cooper and River Bend. I was also in charge of oversight activities with San Onofre and Palo Verde when they were in Column IV a few years back. As a matter of fact, Lou Cortopassi was the ops manager at Palo Verde at that time.

And I've also been branch chief, responsible for the security branch, emergency preparedness. And most recently I've been associated with the oversight activities at Fort Calhoun station, since September of 2012.

CHAIRMAN SKILLMAN: Thank you.

MR. VEGEL: With that, what we're going to do today is, Mike will be primarily speaking on how we implemented the inspection program and going through the history. Because in the, as we implemented the 0350, Mike actually did the majority of the work in coordinating with the other regions, with Headquarters.

And making sure that as we developed the basis document, which was our action plan, that we went through and thoroughly independently verified that all the actions that needed to be done to satisfy the confirmatory action letter, and to satisfy us, that Fort Calhoun station was safe to operate, being sure the rad -- the inspections were completed. So, with that, I'll turn it over to Mike.

MR. HAY: All right. Thank you, Tony. A lot of what I'm going to go through initially has already been discussed in some detail from the Fort Calhoun station. So, I will still go through this material, and obviously give you the NRC perspectives. And obviously, if you have questions that's what we're here for.

So, to discuss how the plant got into the

0350 process. We've already discussed that there was a yellow flooding finding that was identified in October of 2012, during one of the NRC's component design basis inspection activities.

CHAIRMAN SKILLMAN: 2010.

MR. HAY: Yes, I'm sorry, 2010.

CHAIRMAN SKILLMAN: Yes. Thank you.

MR. HAY: And just to I guess specify what the, what one of the particular issues of that was important to that finding was the, for the intake structure they had a steel plate barrier that only went up a few feet. It didn't go up to 1,014 feet, which is the design basis flood level for the plant. And so, the strategy was to place sandbags on top of that steel plate.

And when the inspectors asked to show a demonstration of how they would basically put sandbags on top of the plate up a few more feet, it was realized that that strategy wouldn't be adequate for the flood conditions. So that was one of the particular issues there.

And then we talked extensively on the fact that the plant experienced a floor condition in 2011. They had previously shut down in April, and the floor started in June and went through September. During the flood condition they experienced the switch gear fire of the 480 volt system. And we talked a little bit about the cause of that.

They had replaced these breakers back in 2009. There were some design and maintenance activities that weren't adequately implemented, which over a few years of operation ended up resulting in a catastrophic failure.

The confirmatory action letter was issued, the first one, in September of 2011. And at that particular time the focus of that confirmatory action letter was to deal with recovery actions for the flooded conditions. Also in 2011 there were a number of greater than green security findings that were identified.

Also in 2011 the NRC issued a, our disposition, the white finding, that was related to the reactor protection system issue that dealt with a contactor that basically had a shading coil that was not staying in place. And it actually dropped out of its spot and caused the contactor from being able to open if there was a reactor protection system actuation needed to SCRAM the plant. That was determined to be a white finding.

So you had the yellow flooding issue coupled with the white reactor protection system issue. And that moved the plant to Column IV of the NRC action matrix. And that occurred in September of 2011. We were, at the same time we were doing inspections to follow up on the fire issue. And those inspections were completed, and the NRC disposition, the breaker fire, as a red finding.

Based on the fact that the plant was in an extended shutdown with significant performance issues, and a operational event that dealt with the switch gear fire, the decision was made to place the station into the Manual Chapter 0350 process in December of 2011.

Because the initial CAL really just dealt with the flood recovery actions, the NRC issued a revised CAL. And that CAL incorporated the flood recovery actions, and added into it the specific items that dealt with the performance problems that we just talked about.

Now, we've already talked about the fact that there was a restart checklist. And that was incorporated in that last CAL. And that restart checklist identified the major areas that the licensee would have to focus on with respect to flooding, recovery, and the significant performance issues. However, we, the NRC didn't have a real specified inspection strategy on how we would look at all of these various areas of the restart checklist.

Not only was that a complication for the NRC's ability to implement the oversight activities, but it also was important for the licensee, so that they would understand what specific inspection activities the NRC felt necessary to ensure the plant was safe for a future restart.

So, in November of 2012 we issued what's called a confirmatory action letter basis document. And that is a living document. And it provided the inspection strategy, and it also provided the inspection status of where the NRC was at with the various specific elements that were contained in it. And we used it in a number of ways.

One is, because it was a living document, as we performed the inspections we would document those inspections in the inspection reports. And then we would update this basis document, and issue that to the public, so that the public could follow along, and the licensee could follow along with the specifics as far as what areas had been previously looked at and found acceptable or not.

And this came to be very important during our routine public meetings out at the site, where there was a lot of public involvement. And they appreciated having the understanding of what the NRC had looked at. And this document also provided which reports to go look at, so they could pull it up out of the public document system.

CHAIRMAN SKILLMAN: Mike, is the CAL basis document unique to the 0350 process?

MR. VEGEL: Do you want to be --

MR. HAY: Yes.

MR. VEGEL: -- to go first? And then I'll add to that.

MR. HAY: Yes. The 0350 process, as far as the procedure, does not require the creation of a basis document.

CHAIRMAN SKILLMAN: Yes. This is the first I've heard of that document. That's why I asked.

MR. HAY: Correct, correct. You know, because of the extent of problems that were being dealt with at the site, where you had, you know, elements of flood recovery, you had a number of safety significant performance issues.

And as the licensee was going through their collective evaluations to identify, you know, what sort of programmatic and process issues needed to be fixed, we recognized that the extent of what the NRC needed to look at was fairly large.

And so, we wanted to be able to clearly home in on how we were going to do the inspections, so that all of those elements could be looked at, and kept track of. And so, you know, if it was a smaller scope I don't think a basis document would have been needed.

But because of the large scope at Fort Calhoun station -- And the basis document covered a little, right around 460 specific items after we figured out what we were going to look at. And so, you can only imagine if you didn't create that kind of a document, it would be hard to understand when were you done with the inspection activities.

MR. VEGEL: Yes. And to kind of answer your question. We call it a basis document. But really it's like a, for D.C. Cook we used to call it the restart action matrix to identify the specific issues. Because during this time period you had no performance inspections.

We had flood recovery actions. Then we had other inspections to identify issues, the yellow ones. But there was no one sheet of music, or one document that tied it all together. And that's what we did. Because we had the same challenge at D.C. Cook years before, to also consolidate. And that's where we first used the matrix, we call it.

But this time we call it the basis document. It's the same kind of concept, to lay out exactly what needs to be done, and how everything kind of fits together. Because, as Mike had said, then the licensee would know exactly what we're going to be, you know, looking at, and what they need to be done to be addressed.

And also, we checked with them before we issued it, to make sure they understood was it aligned with their priorities as well, as well as with ours. And then from, as Mike had mentioned, the yearly help from a public communication, that the public could also follow, you know, through what we were doing and why we call it a basis.

Because the public would ask us, well, how are you going to know that this issue's addressed. We've got to answer that question, that we did this, all these inspections, these specific activities. And you can read about it in these inspection reports. That's why we call it a basis document.

CHAIRMAN SKILLMAN: Thank you. Well done.

MEMBER SCHULTZ: Tony and Mike, just to expand that a little bit further perhaps later in the discussion, it sounds like a very good practice. And, Mike, your comment was, perhaps in a different situation, where the project wasn't so large it may not be necessary.

I'd argue that it sounds, as you've described it, Tony, that in every program process for 0350 it would be good to have. Maybe it would be small if the issues were small.

But for the purposes of communication, transparency, and not only with the licensee, but the public as you've indicated, or with the public as well as the licensee, put it that way. It sounds like a good practice, and a good improvement to the --

(Simultaneous speaking)

MEMBER SCHULTZ: -- way in which one gets out of the situation if one gets into it. Valuable to the licensee, valuable to the regulator, and so forth.

MR. VEGEL: Because Manual Chapter 0350 is not a frequent Manual Chapter that we use. And it's very important that we shore it up. And we've done that, even though we're not quite done yet, we've already conducted a lessons learned. And out of that we pulled out some of the good practices, and some things that we maybe could have done better --

MEMBER SCHULTZ: Sure.

MR. VEGEL: -- from the implementation, to capture that. And that's going to eventually result in, you know, I guess changes or enhancements to the Manual Chapter 0350 document.

MEMBER SCHULTZ: I'm glad to hear that. Thank you.

MR. VEGEL: You're welcome.

MR. HAY: So this next slide kind of gives everybody a visual of what we just talked about. So, we had a confirmatory action letter that, enclosed in that action letter was a restart checklist. And then supporting the restart checklist is this basis document that provided the specificity of what the NRC was going to be looking at, so that we could adequately review the areas of the restart checklist.

And I wanted to, and I know as background information we provided you all a December 16th, 2013 letter. And it's titled "The Recommendation for NRC to Close Confirmatory Action Letter EA-13-020, that Supported the Restart to Fort Calhoun station". This document provides a fairly good example of what the basis document did for us.

And let me just go down to where we have the restart checklist. So, here's a picture of the restart checklist. And, you know, it covers the areas that you saw previously from OPPD's discussion where you had, you know, Area 1, which was the causes of the significant performance deficiencies that dealt with the covered findings. And so, that's the, this is the restart checklist here. And obviously it covers a lot of different areas.

And then we created this document here, which is the basis document. And so, you can see the basis document was structured where Area 1 dealt with, you know, the causes of significant performance deficiencies.

And so, for example, the flooding yellow finding, the first three specific items that the NRC looked at was the licensee's evaluation for the contributing and root causes, they're extended condition review, and the corrective actions that came out of that.

And then in addition to those three items there were a number of additional items that we specifically looked at that, you know, and as you can see, not only do we talk about what the issues is, but we describe was it, if it's an LER or a violation. And then after the inspection is complete, under the status we would put, you know, it if was completed successfully, that it was closed, and a certain inspection report.

And then we put the ML number for that report. So this is what we used. And I think what's important is, like if I go to the Item 1 Charlie, which is the red breaker finding, you can see, you know, we were consistent with looking at the licensee's root cause evaluation, extended condition, corrective actions.

But for this particular item we also specified that we were going to look at a lot of the specific activities that dealt with the licensee repair efforts, as far as rebuilding the load centers, replacing certain components, post maintenance testing activities.

So, you can see from that red finding there is a, I think there's around 26, 27 different inspection activities that we did just for that one specific issue. So that kind of gives you the flavor for how we put the basis document together. And how it clearly articulated, you know, for every given restart checklist area, what are the minimum activities that the NRC would look at to verify that they were adequately conducted.

Now, I'm going to try to go back to the slides. There we go. Now, as we were going through the process of updating the CAL and the basis document, the licensee was also performing a lot of evaluations. And as we previously discussed, throughout their efforts to identify the extent of their problems they were quite effective in identifying some other issues that had potential significance.

One of the items dealt with a number of safety system functional failures that were reported to the NRC. And there is a performance indicator that is associated with safety system functional failures.

And they actually went past the green threshold for those safety system functional failures.

I believe the threshold is more than five. At the point in time that they crossed the green threshold they had nine. And as a result of their continuing look at their design basis they've identified more since then.

Also, as we've discussed previously, they found, you know, deficiencies with respect to the containment internal structure, and with the containment electrical penetrations. And so, we had already issued a CAL that at the time we thought had most of the significant issues.

But when these came up the panel decided that these three items were important enough to be added to the restart checklist. So, we issued a revised confirmatory action letter in February of 2013, which simply added those three items to the restart checklist. And as you can expect, because they added to the restart checklist we updated our basis document that would clarify what we would inspect for those three items also.

So, now I'd like to spend a little bit of time and talk about the NRC activities to follow up on these 460 specific items. You know, it was a huge collective effort by the NRC, that involved approximately -- I'm just talking now in 2013, prior to plant restart. We actually started our inspections in the February time frame of 2013. And they continued up to plant restart in December.

We had approximately six teams that were developed. And they ranged anywhere from three people up to 15 people teams. We also had the resident inspectors on site, who did continuous inspections, along with a number of specialists that went to the site to follow-up on specific items.

The, excuse me, the residents typically issue inspection reports every quarter. We ended up accelerating that because of the amount of information that we were looking at. So, we actually issues a resident report every six weeks. And obviously, the team inspections, that would be its own inspection report.

We had inspectors that supported us from all four regions, and Headquarters, you know, just to kind of talk briefly about some of the team inspections. We had two security team inspections that went out, to follow-up on the security issues.

We had a 15 person team that went out, that really focused on the corrective action process, and a lot of the elements that dealt with design control at the plant, such as the red breaker fire, the flooding mitigation strategy.

And we had a number of other teams that went out later on, prior to restart, that followed up on some of the issues related to high energy line breaks. That turned in to be a very extensive inspection activity. We had a contractor that had expertise in environmental qualifications. And I actually was able to acquire him for a six month time period, where he solely looked at high energy line breaks, and the qualification of equipment.

The inspection activities were very complex and technical. And so, it required a lot of expertise from outside the region. For example, the containment internal structure, you know, as the licensee talked about.

The internal structure was found to have some nonconformances to the design requirements. And so, the licensee did an operability evaluation to demonstrate that even though the structure was non-conforming, that it would still be able to support safe plant operations. And in order for us to review that OP EVAL we had to get some expertise from headquarters and other regions to do those reviews.

And it took our staff approximately six to seven months of review, just for the containment internal structure review, to come to the conclusion that the licensee had, that it was operable. And so, there are limits of the containment internal structure that are currently non-conforming.

And those elements are currently contained in what we call the post restart confirmatory action letter, whereas, OPPD discussed this morning, they have a number of actions that they're taking in the next outage to restore the structure to its design basis.

MR. VEGEL: We were, during these inspections we were looking at the end in mind. And in the big scheme of things we were looking at, you know, the Fort Calhoun station, to ensure that, to deal with the startup safety. We don't only look at the people, the processes and the equipment, to make sure they'd be, at the end, adequate to support that restart.

So, like for operations, we were looking at operations readiness six months, nine months ahead of time, to make sure, because after they'd been shut down for all that period of time, waiting until the very end is not the time. But it's really, it's hard to see in the simulator, see what they're doing to make sure that their operators are, you know, getting ready.

And that even though the plant was shut down, that that control and decorum was up to operations standard. And that was an area where Fort Calhoun did very well, from my perspective, of really sending people out to other sites, and getting operational experience, you know, especially some non-licensed operators.

It also, you know, some challenging scenarios in the simulators, and then watched them closely from day to day operations in the, you know, even if the plant's shut down in the control room, and getting help from Exelon and that. So that when the time came for the plant to restart and heat up, that one you had this movement.

So they did that, that we were looking early on. And some of these, you know, processes, that was, sometimes it was a little bit tough to make the call, you know. Like the procedures, they had a large backlog of procedures that needed to be correct and, you know, up to standard. But to evaluate the ones that are important, that they are addressed, and that the corrective actions are adequate.

And for equipment, that was, we were looking at equipment to the night before, you know, the restart decision. Because things, issues would come up. Or sometimes, for some issues, it took a little bit more work to be able to disposition, then say, yes, it is adequate to support restart.

MR. HAY: Yes. And just to add a little more, you know, one of the major overall conclusions that we had with respect to the inspections done prior to restart is, the licensee did a really good job identifying a lot of areas that needed to be either addressed before restart, or addressed following restart, continued to improve performance.

Where we found issues primarily dealt with the licensee's ability to effectively evaluate some of these problems. So, such that there, you know, there's an adequate resolution. And most of the times these issues dealt with understanding the design basis of the plant.

It's an old plant. I think someone mentioned it's a pre-GDC plant. And so, there's not a real well defined design basis for everything at the site. I'm not saying it's not good. But definitely, when you get into the details of wanting to understand something like flood mitigation, you know, what was the basis for the 1,014 foot level? It just really wasn't there.

And so, what we found is a number of issues that were identified by the licensee. But just from a design basis engineering type standpoint they were not effectively evaluated and resolved. And as those issues compounded it became apparent to us and the licensee that they needed to do some effort with the design basis of the plant.

And they did commit in the post restart confirmatory action letter to conduct a design basis reconstitution project. And I know you asked about how they might have responded to the 1990 50.54F letter.

Just to give you a little perspective, Fort Calhoun had done a design basis reconstitution prior to the '90s. And it was reconstitution that was basically a commitment that they made based on performance problems prior to the '90s. And when they implemented that process they did find a number of items.

But again, some of the issues that were identified recently were identified back when they did the initial reconstitution. But they weren't adequately dealt with by the facility. So, when the 1990s came out, and all licensees had to do a design basis reconstitution, Fort Calhoun was able not to have to implement that, because they informed the Commission that they had already done so.

So, anyways, that's, you know, there is still a need to do it. And I'm not saying the initial effort wasn't a good effort. I just think there's a population of questions that the licensee needs to answer, based on that initial effort. And hopefully as they go through in the future effort, you know, they'll find new things that can be improved also. I hope that clarifies a little bit.

CHAIRMAN SKILLMAN: It does. It does bring in the question past culpability and issues of 50.72 and, you know, 73 regarding reportability. It just seems like they, this unit was able to run for a long time with a fundamental weakness in their discipline for criterion 3, design control, and 16, which is corrective action. For some reason a lot of stuff just seemed to slip through the cracks.

MR. HAY: Yes. And if you were take a look at the number of issues that we found, I mean, there was approximately 140 NRC regulatory issues that were dispositioned last year. Albeit the vast majority of those were green issues of very low safety significance.

There were a couple that were more safety significant. For example, the tornado missile issue, where you noticed, you know, there was a lot of components outside of the structures that weren't adequately protected for tornado missiles. You know, that issue was determined to be of white safety significance. And it was dispositioned a few months back.

And currently we're finishing up on a safety significance determination for those areas in the plant that weren't properly looked at for high energy line break scenarios. And although we haven't yet concluded that dispositioning of that issue, it appears right now that it will probably be greater than green, probably around the white range also.

But both of those issues were dealt with by the licensee prior to restart, so they're not current safety issues. There is some elements of the high energy line break deficiencies that currently exist. However, the licensee was able to isolate the aux steam piping to those areas of the plant.

And so, right now there's no potential for a high energy line break in those areas, because there's no high temperature or high pressure fluids in those pipes. And that's incorporated, like I said, into the post restart confirmatory action letter for them to resolve that.

CHAIRMAN SKILLMAN: I'd like to, if I can, kind of turn the spotlight 180 degrees. So, we're kind of looking at the owner/operator having gone for a long time with weaknesses. In that same time period you had residents, and you had special inspections. How did those actions of oversight fail to find this much earlier than 2011?

MR. VEGEL: Mr. Skillman, you bring up a very good point. And that was one of the -- I mentioned previously that we did a lessons learned. And that's specifically what we also looked at, to say, okay, now they're into shutdown, we found all these areas. As you stated, you know, compliance to criterion 16, compliance to the design control issues, criterion 3.

CHAIRMAN SKILLMAN: Three.

MR. VEGEL: Why did we not --

CHAIRMAN SKILLMAN: Catch it.

MR. VEGEL: -- identify? And not to finger point, or anything to that. But just -- And we found that just, we've done inspections. And in hindsight we had that information. But we didn't integrate it, per se. Like, for example, from criterion 16, the corrective action piece.

We had opportunities where the plant was in Column II. And they had issues with design control, and corrective action program issues. But we put a plan together and say that they're going to correct this thing. At the same time we had a problem identification and resolution inspection that said, hey, the corrective action program implementation is poor.

In hindsight if we put both two together of these issues and how they were struggling, and that the corrective program was weak, we probably could have identified some of these areas earlier. And not just when we had a design control violation, just to say, okay, send me a corrective action program to address. But to focus more on the corrective action piece, to verify that, knowing that they're having a problem with the program.

And well, it's hindsight. But I think there was a lost opportunity. So, from the lessons learned in the recommendation to shore up the communication and the implementation of like, when we do mixed cycle or end of cycle, or such, to put forward specifically these type of issues are discussed. And then --

CHAIRMAN SKILLMAN: Let me ask one more. INPO is doing E&As in the same time period. And they look at design control. They look at material condition. They look at processes. How did this plant manage to steer through those activities with INPO E&As? Maybe I should ask them.

MR. VEGEL: Yes. Ask INPO, yes.

CHAIRMAN SKILLMAN: I'm curious. Is this a matter of being --

MR. CORTOPASSI: Yes. And in fact the -- I'll just stand here.

MEMBER STETKAR: You have to use the

microphone.

MR. CORTOPASSI: Oh.

CHAIRMAN SKILLMAN: And give your name, just so it will be on record.

MR. CORTOPASSI: Yes. If you look at the plant evaluation that was completed in, right before the outage. So it would have existed in the March 2011 time frame. There's two areas for improvement that are particularly noteworthy.

One in the OR area that dealt with safety culture, that I think was right on. And then one on understanding the design basis, which used several examples, including the flood recovery, excuse me, excuse me, including the yellow finding that I think also was right on. That was in EN-1, which is engineering oversight and leadership.

So, I'm not going to talk INPO scores. But they were indicative of the time of what we would expect, you know, from a plant performance standpoint. And I think those two areas for improvement in particular, you know, for the INPO staff were essentially right on.

And we used not only the INPO areas for improvement, including the accreditation areas for improvement, as part of our diagnostics looking. We used the 95003 process, because it's meaningful data that again, you know, in retrospect was accurate. But at that point in time the rate of decline, again, and exasperated by the flood, is the results that I talked about this morning.

CHAIRMAN SKILLMAN: Thank you, Lou. Mike and Tony, thank you.

MR. VEGEL: You're welcome. I hope I answered the question. But relative to lessons learned, we're also looking at component design basis inspections, to put more focus on design control, and those type of areas that need recommendations to augment those procedures that are currently in process.

You know, looking ahead so that hopefully, you know, these kind of issues will be identified sooner. And we, in looking back we also found that we had a tendency sometimes, when we did a component design basis inspection, we would sometimes look at the same areas, you know, every three years, electrical or whatever.

It's to also to pinpoint and change the procedure, our design basis inspection procedure to force us to look at the previous, to look at different attributes. Look more maybe at containment, or some of the structural things, or other areas.

The containment penetrations is a good example. The issue there was Teflon. That was an area that everybody almost assumed was addressed. All plants took Teflon out, right? But at Fort Calhoun it wasn't done. But so, also we've had a recommendation in the CDI procedure to look at some of the old generic issues that were out there, and do a spot check.

Was it really done? And, how is it dispositioned? I think that's a healthy look. Because that was one that surprised us, frankly.

CHAIRMAN SKILLMAN: Okay.

MR. HAY: Now, in addition to the inspection activities, we got a lot of support from Headquarters. And a couple of the specific items we've already talked about, with the containment internal structure. We got a lot of support from the technical experts.

But also, there was a couple of licensing actions that were needed prior to restart. One of them dealt with, you know, a licensing amendment needed to deal with the tornado missile issues. And the other dealt with the high energy line break.

And I'd like to, you know, just make a comment that, you know, both of these issues were initially evaluated by the licensee as being able to perform corrective actions that they could address without a licensing amendment. And so, they were using an operability process to say it's operable but non-conforming.

And it took a lot of NRC engagement, working through the Headquarters, technical experts, and then with the licensee, to get OPPD to understand that licensing actions were needed to adequately resolve both of these issues.

And, like I said, a number of mods have already taken place to put the plant back to its design basis, for both tornado missiles and high energy line break, with the exception of the one area dealing with aux steam for high energy line breaks. And, we did what's called task interface agreements with Headquarters.

And that's where we get Headquarters' expertise to help the region review certain items. And we've already talked about the containment internal structure. And just to specify what we needed Headquarters to look at.

Since the internal structure was in question, I think someone already mentioned you have to look at all the different loadings that would be applied to the structure. And one of those loads includes the actual LOCA. And so, there's a specific type of analysis, called a GOTHIC analysis that's used, that was used by the licensee, that assumes different pipe breaks inside containment, and how those loads would be transferred to the internal structure.

So, we did get Headquarters' support to look at that analysis. After the GOTHIC analysis was completed, the licensee was then able to use a finite element pipe analysis, that would then look at the structure from all the other loading criteria, as far as seismic, and whatnot. And we had another group of experts that looked at the finite element analysis.

So, like I said, after about six or eight months of work on our part we were able to conclude that the containment internal structure is operable, although non-conforming, with a number of actions that the licensee plans to implement this coming up outage, to restore the structure to its design requirements.

MR. VEGEL: If I may add, this is not the first time we've been involved with the Manual Chapter 0350 implementation. But I have to say that for Fort Calhoun I think the cooperation and the coordination between the regional, the inspectors, and the folks here at Headquarters, some of the technical experts, the licensing folks, was really awesome.

Because there was a lot of issues that kind of bounced back and forth. There was inspection issues, got to the experts and begin licensing. But they worked through it really well, in a timely manner. And sometimes it's tough to do that. And it was extremely well done.

And a lot of credit goes to Louise Lund, who is the Vice Chair for 0350, Mike Markley, Joe Sebrosky. Everybody worked together really well on some really tough issues, especially when you have a really good design basis as they did.

Not as clear as if it had been a new plant, per se. But to work through the issues is really an agency effort, not just Region IV or just an inspection, but also from the technical staff here. It was really good.

MR. HAY: So, after the inspections were completed, obviously the 0350 panel is chartered with ensuring that all the elements of the restart checklist were adequately addressed by the licensee. The panel went through that process in the early part of December. And, you know, it took approximately 23 hours of NRC inspection activities in 2013. But at the end of the day --

MR. VEGEL: Twenty-three thousand.

MR. HAY: Twenty-three thousand.

MR. VEGEL: You said 23 hours.

(Simultaneous speaking)

MR. HAY: Yes. It took a little longer than that, 23,000 hours of NRC inspection activity. And the panel did conclude that the plant was safe to restart. And the panel provided that recommendation to the Region IV regional administrator and the director of NRR.

And, you know, on December 16th the NRC, actually on December 17th the NRC determined that the plant was safe to restart. And they commenced restarting on December 18th.

MR. VEGEL: This might be a good time to pause. Is there any questions for us regarding, you know, how Fort Calhoun got the 0350 oversight? And just, you know, leading up to the restart decision? And how we implemented the --

CHAIRMAN SKILLMAN: I do have a question. I'm hesitant to ask it. But I'm going to ask it, because it will get it out of my system. Dr. Rempe kind of put her finger on this a couple of hours ago. How much did it cost?

I would ask the NRC staff, in the aggregate total, as you begin to deal with all of these issues, did it occur to you, or did you tumble to the notion that the licensee had, in fact, chosen to not take activity, to not do work because of budget limitations? They were just not permitted to spend money, so they didn't do stuff?

MR. HAY: You know, I can't tell you that the licensee was hesitant to take those actions because of monetary reasons. There were times where obviously the licensee was looking to do things like heat up the plant, and then eventually to restart the plant. And they were under a, obviously a timeline, a self-imposed timeline to have those activities happen.

And the NRC did have to weigh in a couple of times to say, you know, the plant's not ready to heat up yet, because you need to deal with the tornado missile issue differently than what you currently plan to do. And I know we had discussions on some equipment that they were working on, whether or not they had fully looked at the full extent of the condition.

But in all of those cases, after having a lot of discussions with them, they ended up, you know, doing what we thought was the prudent thing to do. And they were able to do their activities, I think, in a timeline that was acceptable to them. Although, it may not have met what they wanted to do initially.

But it wasn't, from my perspective it wasn't because of monetary pressures. I do think, you know, when the restart decision was made the licensee, well OPPD was probably getting close to a decision, you know, what's left? And if it's extensive, they would probably have to make an economic decision.

But from my standpoint, dealing with the issues that I dealt with, you know, it was never, at least communicated to me that we just can't do that because it's too cost prohibitive.

CHAIRMAN SKILLMAN: Let me ask OPPD if you might want to respond to that. I'm not trying to put you on the hot seat. But that's always a sensitive topic that those who have been out in the industry can listen to the heartbeat of a plant. And often the workers will say, well, we just, we're not going to do that because we've been told we can't afford it.

MR. CORTOPASSI: Yes. I think Mr. Hay hit it accurately. There's a couple of examples I would use. Equipment service life was one where we had, and the RPS contactor was an example where it ran behind, ran beyond its useful life.

And so as we worked, you know, from our perspective on looking at that issue, and then the spare parts issue was another one where we thought, hey we, you know, based on our indication that this was going to be a big issue.

Once we worked through both of those I think we came up with a very logical pre and post restart scope of work. Got challenges from that, you know, had to go maybe an extra layer or two deeper to prove what we assumed, just based on the extensive sampling that we'd done.

But for the most part, you know, the ones that would probably have concerned me the most, if we had to pull the containment internal structures forward, just because of, it's a first of a kind activity. And two, you know, to do that in an emergent fashion, you know, which we've seen with some respects in the industry, you know, some of the engineering issues that have resulted as something, you know, resulted from those type of decision.

But for the most part the rest of the decisions, when we said we're going to go address this scope of work based on this criteria, and was inspected as such, those things lined up pretty well. The tornado missiles was probably the biggest, you know, unanticipated expense if I think about the projects that we did during shutdown.

MR. HAY: You know, if you were to kind of change your lens, and back a number of years before you came on the scene, were there, was there a culture where the team and the station did not want to do things because it "cost too much money"?

MR. CORTOPASSI: You know, I'll say no. And I base that on, you know, the 2006 outage, where both steam generators replaced, head replacement, you know, pressurized replacement, the main transformer replacement, really setting the plant up for extended power upgrade, which we may or may not do.

Right now that ball is back in our court. And I look at some of the other investments that have been made. The last refueling outage also put a digital control system in for the main turbine, rerouting the generator.

And I looked at John and, you know, Joe, a longer time before you. I mean, I just look at, you know, the basic center line, the major components are all really set for end of life, you know, for the asset has been invested, especially at that level, you know, for us to effectively be able to run until 2033.

And there's challenges, you know. Right now one of the strengths that, you know, the Exelon fleet brings in just the long term asset management process, design it once, implement it, you know, multiple times. A lot better oversight with respect to outage scope, and how we're going to manage future refueling outages, and the equipment reliability. But again, I look at, you know the major projects, the major investments are behind us.

MEMBER RAY: But, Dick, I would say the major investments can put pressure on the other things that are now the topic of conversation. It would be very difficult to make a judgment about that.

CHAIRMAN SKILLMAN: Yes, I agree. Lou, thank you. Tony, Mike, thank you. Let's go on.

MR. VEGEL: I don't know of any examples where, you know, money was the issue. But two is, when you get into the NRC perspective, and you have to make a restart decision, it is sometimes difficult because inspectors will try, you know, will, because they have a good safety conscience to everything we purpose.

But the early on, to say, okay, it's got to be adequate, the plant has to be safe. The important things have to be addressed. And, going back to the basis document, that was very important. To kind of articulate, this is where we're setting the bar. And if some new safety issue comes up, we will add it to it.

But it has to, that's where the panel comes in to make that decision. Because it's too easy at that time to somehow, to go for perfection, or some issue, and maintain that discipline. But to be able to, as a panel, make the decision saying, no, you have this AW restart issue, this has to be addressed. And then communicate it, you know, to the licensee.

That too, that we get their perspective

that this is the right thing to do at this time. So, it does take a coordination and a lot of effort from that perspective. And we'd meet almost every week, sometimes two or three times a week as a panel to discuss some of these issues, to make sure that we weren't unnecessarily putting, you know, a regulatory burden on the --

CHAIRMAN SKILLMAN: What I was really trying to get to is this, when the licensee doesn't have the keys, and wants to get the keys back, when they're in 0350, they're going to behave one way. In the years before they got into that situation they were behaving the way they were behaving. That resulted in some of the problems that you discovered.

So, the real question was, in that earlier time period were they cutting corners that has to do with nuclear safety, which is what we're here for. So, that was the real thrust of my question. And I agree with Harold Ray. This discussion has kind of been an aside. And it can't go very far here.

But those of us who have been in the plant sites know that in some plant sites there's this very high attention to duty, and other plant sites not so much. And you can tell, based on equipment performance, really, hits on criterion 3, how the corrective action program is performing, what work management looks like. You put a couple of those together, and you can figure out pretty quickly what that plant is up to.

And you've put your finger on the big hitter items here, criterion 3, criterion 16, work management. And as a consequence you found high energy line break, you found EQ, you found parts, you found scope of supply, procurement issues. And those are the ones that will take you out. But none of those started with the flood.

MR. HAY: Correct.

CHAIRMAN SKILLMAN: Extreme.

MR. HAY: That's right. And I, you know, thinking back at the collective evaluations that OPPD did, they identified the fact that historically they did have a lack of conservative decision making, managements that, management styles that weren't holding people accountable.

And, you know, a lot of what Exelon management model is bringing to them is that governance, and that decision making process that hopefully going forward will allow them to operate from a lot better viewpoint.

CHAIRMAN SKILLMAN: Thank you.

MEMBER SCHULTZ: Going forward just one page. Mike, you've already identified and talked about those continuing activities that the staff has concluded is extremely important. And Lou mentioned them as well in his presentation. So, I think moving forward you're on the right page. And those have been identified, I believe because those were major issues that before --

MR. HAY: Yes.

MEMBER SCHULTZ: That led to the events associated with the corrective action letter and so forth. A lot of, since you said stop, I wanted to focus a moment on this slide. Because, when I saw your number, the 23,000 hours looks like a big number.

But when I heard all of those activities that you displayed earlier, it sounds like a fairly small number. So, it means one of two things. Either you didn't count everyone and their activities, and I think that's probably part of the answer.

But the other part of the answer, I really believe, is that, and I wanted to congratulate both of you, but also the rest of the staff that participated.

You must have been able to bring to bear, as you said in your presentation, some, an important assembly of experts, specialists, staff contributions, that have involved not only the region, but other regions as well.

And I think it's very impressive that the management of the activity has been done so well, just in that regard, in the overall inspection review. And it must have also reflected the ability to communicate well with the licensee. So, I just wanted to state that while we pause.

MR. HAY: Yes. Thank you for that. And I, going back to the, you know, the basis document. I think after that was created it allowed us to specifically stay focused on what we were going to look at. And so, you know, I think if we hadn't created that, you know, the outcome might have been different.

Because, you know, even though it was 460 items, which a lot of people choked on, that seems like a lot. You know, once we got going, once the licensee knew what we were going to look at, you know, they could tell us, we're done with that. And then --

MEMBER SCHULTZ: And that was a subset of the licensee's activity list?

MR. HAY: Correct.

MEMBER SCHULTZ: Correct.

MR. HAY: Correct. So, I think being able to, you know, highlight what we're going to look at, that prepared the licensee to understand what we're looking at, so that they could provide the inspectors a package. And it made it a lot more efficient. And so, anyways, I do thank you for that.

So, after the confirmatory action letter was closed, the plant was able to restart. And coupled with the closure of the confirmatory action letter that basically was needed with the restart checklist, even though we closed that we opened up a new confirmatory action letter.

And that confirmatory action letter deals with a number of key areas that the licensee is going to continue to take actions on, to improve performance. And, you know, there's ten key areas. And I put four of them here that are important ones.

You know, we've talked about the importance of the corrective action process, and the importance of design basis reconstitution. Those are two of the key areas.

MEMBER RYAN: Mike, could you talk a little bit about design basis reconstitution, please?

MR. HAY: Sure. In essence what it means is, the licensee has committed to looking at each safety system at the plant. And looking at, you know, going back to day one when they were licensed, and looking at, you know, the updated safety analysis report, the design documents and calculations. And, you know, going through each system, you know, systematically from ground zero to today.

MEMBER RYAN: Brick by brick, so to speak.

MR. HAY: Correct, correct. And, you know, that will allow them to find gaps on how they were originally, I won't say originally licensed, but find gaps in what's in the basis, so they can shore up those gaps. And, you know, there are a number of issues that we're expecting and they're expecting will be identified. And they'll have to deal with it.

I know, you know, just from last year alone they identified a number of issues, whether it be pump set, RN runout conditions, or the tornado missile issue, containment of internal structure.

So, you know, based on all of these different examples that were identified, you know, both the licensee and the NRC recognize the importance of them going back and actually implementing a design basis reconstitution, like all plants have previously done.

MEMBER RYAN: Thanks. That's real helpful. I mean, that's a big job for sure, and of course.

MEMBER RYAN: It is. And, you know, one of the things that they also have is custom tech specs. So, they've got the original tech specs that they were licensed to. And, you know, this effort will, you know, hopefully allow them to be set up to possibly go to, you know, improved tech specs. That's a decision that they'll have to make. But I know that is on their plate as something to evaluate.

MEMBER RYAN: Thank you.

MR. HAY: Now, along with the ten key areas, as we talked about the post restart confirmatory action letter also deals with the items like the containment, the internal structure that needs to be restored to its design criteria, and the high energy line break areas that currently have the aux steam piping isolated.

So, in totality there's approximately 180 specific actions that the licensee has committed to implement related to the post restart CAL. So, since the plant restarted there's been a number of inspections. And going back to, I think a comment that Tony made, you know, operations is one of those areas that we have focused on.

You know, during plant heat up we had continuous around the clock inspector coverage of control room operations. Also during plant startup we had approximately, I want to say seven to ten days' worth of continuous around the clock control room coverage. And the assessment from the NRC was that the operations department did a really good job operating the plant.

They were methodical, systematic. They stopped at the appropriate times where things were identified that may not have been normal. And, you know, before proceeding any further they got adequate resolution of whatever the issues were. So, you know, by and large we really had a good assessment of operations for performance during those activities.

We've obviously continued to have resident inspectors at the site. And we've done a number of regional inspections at the site, cyber security inspections, visible security, radiation protection. And then, just last July we finished up with a 13 person team inspection. And that team looked at the effectiveness of the licensee's implementation of the corrective action process, along with the licensee's implementation of the confirmatory action letter items.

And, let me go to the next slide. That gives the results. So, the results of that last inspection in July were mixed. We found that the licensee was adequately implementing a lot of the items in the post restart CAL. As a matter of fact, we closed 130 out of the 180 specific items. And of the ten key areas we closed five of those. And I won't read them to you, but they're listed there on that slide.

And so, you know, there's still five areas that are left open that we'll continue to follow-up on. But, by and large the licensee is implementing the actions that they've committed to implement, and doing a relatively good job doing that.

However, why I said it was a mixed result is with respect to the corrective action process. We again found a high number of issues that pretty much mirrored the types of issues that we found last year prior to restart, with respect to, you know, not so much -- Issues get put into the corrective action process. Their threshold is low, you know, they do that very well.

But the problem is, you know, evaluating those problems, such that they implement actions that address it. And specifically, to get more concise, you know, it's the more complex issues. The issues that again deal with understanding the design, understanding the intricacies of operability, the 50.59 process. Those sorts of assessments we found a number of problems with.

And the other area that we found problems with was, we, you know, out of the 100 and like 40 NCVs, or violations that we issued last year, we decided to take a sampling of how well they resolved those problems. And so, we sampled 36 of those. And we found five of those that were basically not adequately addressed. Some were closed with no actions taken even.

And so anyways, you know, based on the overall concerns that the NRC had with the implementation of the corrective action process, the panel made a decision that, you know, to the panel that the site should remain in increased oversight of 0350 until the licensee can take actions to deal with the CAP. I think I stole some of Tony's thunder in the next slide.

MEMBER BLEY: Can you give us anything of a flavor for those kinds of items that were either marked as closed or weren't addressed?

MR. HAY: In CVs?

MEMBER BLEY: Yes. The ones that weren't addressed, as compared to the ones that were addressed. Did they at least, were they focusing on the more significant ones? Or was it just a mix?

MR. HAY: Well, and we've had a lot of discussions with OPPD on this. One of the -- To answer your question directly, it was mixed. One of the problems that occurred in the licensee's process is, when the NRC was on site last year, as far as the teams, they asked hundreds of questions.

And a lot of those questions obviously got put into the corrective action process because they dealt with a potential safety concern. And so, at the end of the inspection the NRC team would then debrief the potential deficiencies or findings.

And what failed to occur in the licensee's process is the fact that some of those questions that were put into the CAP were associated with a violation of requirements. And so, they had thousands of things in the corrective action process.

MEMBER BLEY: I think over 50,000.

MR. HAY: Right, right, right.

MEMBER BLEY: That's a massive amount --

MR. HAY: Right, right. And, you know, of those 140 of them dealt with NRC potential issues. And they, you know, they didn't highlight in the CAP that these were associated with NRC concerns. And, I mean, to me, you know, I don't think that should matter.

I mean, if it's a valid safety question that deals with not following the requirements it shouldn't matter if it's flagged an NRC concern or not.

And so, I don't want that to, you know, just because it wasn't an NRC addressed issue, I don't want that to be the focus. Because to us it shouldn't matter. If it gets into the CAP, and it's a real safety issue, it should get handled effectively, whether or not the NRC asked it, or a licensee employee.

MEMBER BLEY: I was just, I've been trying to fathom this thing. And, I mean, if you've got hundreds of things there, that's one thing. But when you have over 50,000, keeping track of those and handling them all right is a pretty tough job.

MR. HAY: Yes. It's challenging. And I --

MEMBER BLEY: But they're trying to get out of a hard spot. So --

MR. HAY: Correct, correct. And no doubt there's a lot on the licensee's plate. And, you know, having the right prioritization of how you resolve issues has to be effective. What concerned us though is those items were considered closed by the licensee. And all actions that were going to be taken were done. And so, that's why, you know, we had a concern with that area.

CHAIRMAN SKILLMAN: Did they reopen those items after you pointed them to them?

MR. HAY: They did. They did. And actually, not only did they, you know, go back and look at each one of those issues, but they're going back and looking at all the issues, going back a few years, I think 2011. Is that correct? 2012. To make sure that they've adequately addressed the issues since that time frame.

MEMBER RYAN: You know, I mean, it would seem to me that if you've got several year’s worth of that kind of data, that it would be interesting to try and figure out in year 1, 2, 3, and 4, what happened that was different in terms of their identification, their ranking, their corrective action, the effectiveness of the corrective action.

You know, I mean, there's so many variables here. There's the people that were doing it, you know, management direction, all different kinds of variables you could chase. I'm just sitting here trying to think about, okay, smart guy, what would you do if it was your problem? And I'll be curious to see how they kind of parse that out to make sense out of the variables.

MR. HAY: Well, I do know, based on discussions we had last week, not only on site but at the public meeting, OPPD is implementing a number of additional oversight activities that will review such things as, you know, root causes, apparent causes, corrective actions, operability evaluations.

You know, they'll have another barrier put in place that's in addition to the normal process. So that, you know, more experienced folks can take a look at those activities, to try to ensure that they're consistently and appropriately conducted, until they can get the design basis reconstitution done, and other -- You know, they're still evaluating all the corrective actions that they plan to take. So, I don't want to talk to those yet --

MEMBER RYAN: Well sure --

MR. HAY: Because I don't know what those are.

MEMBER RYAN: When you're right in the middle of it, I understand that. But it sounds like, I mean, I'd use the word graded approach. If things are okay, things are okay. If things don't seem okay then we'll do a, dive a little deep until it does look okay, you know, trying to find that scope of not okay to okay, and what needs to be worked on in between those two.

MR. HAY: Right.

MR. VEGEL: And right now, like in the corrective action program area, the ball's really in Fort Calhoun's court, to really understand why in the evaluation piece and the resolution piece of the corrective active program -- And it's not a program.

It's got all, you know, it's the implementation, the oversight. Some of the, and some of it might be even organizational, department specific type issues. I'm not sure. But they have to understand that. And, you know, once they understand that, then they'll be taking corrective actions.

And then we'll come back and we'll finally look at that, and see what they got there. Because it is, this is a different time. It's not, you know, sure, there's different factors involved with that.

MEMBER RYAN: It's not a program, it's a lifestyle.

MR. VEGEL: Yes, yes.

MR. HAY: Right.

MEMBER SCHULTZ: I think that goes to my comment too. The assessment team found that the organizational effectiveness, safety culture, safety conscious work environment is being implemented. That's good news.

But at the same time, one of the, or a couple of the key measures that one would use technically to evaluate that would be the implementation effectiveness of the corrective action program. And that's not on the high mark list.

And the other one would be evaluation of things like 5059. So, there's more work that needs to be done in the, over time, in having that, the effective programs bear the proper fruit in terms of implementation at the site. Lou, would you respond to that? I think I'm saying what you would. But I'd appreciate it if you put --

MR. CORTOPASSI: Yes. We echo that. And, you know, Mr. Hay kind of pointed out, it's just on a focus on why we missed, you know, response to some of the violations. Although it's a very rich set of data that we put into the common factors. And I touched on it a little bit on my slides.

We're not satisfied with the results at all. And it pointed to some additional work, primarily in design engineering. And I can even split that down to design mechanical. And to some respects, we continue to evolve with the operability determination process, and just how we share those lessons learned across the shift managers, across the operations department.

How the shift manager, you know, truly

making him a manager to use the organization when some of the stickier situations come out. You know, how they activate the duty team, and how they really organizationally come up with a response, is really what we've been focusing on from a bigger picture standpoint.

But you're right, you know, the foundation for everything we do, the safety culture, safety conscious work environment just absolutely has to be there. So, the assessment team says, yes, you've done your actions, you've got good measurements, you're adequate with a, you know, with room to continue to improve. And we echo that.

We don't think we're there in that area either, especially because it does tie. It ties, and they're so intertwined when we get down to the corrective action program.

That said though, we think we've got very meaningful metrics down to the department levels. And that with this set of data we're taking some broad based things, but really a much more surgical approach with the areas in the organization that need the additional help, additional oversight, or additional knowledge and skills.

MEMBER SCHULTZ: Thank you.

MR. HAY: Okay. With that, I'm going to turn it over to Mr. Tony Vegel.

MR. VEGEL: So, Mike talked about the last problem identification resolution inspection, and the results of that. And based on that we, the 0350 panel will remain, provide an oversight at Fort Calhoun.

Then what's that mean? Do you have periodic public meetings? Well, to be honest with you, I'm not looking forward to having another public meeting, December and January in Omaha. But it is what it is.

In all seriousness though, I think those public meetings are very, very important to make the public understand where we're at. And I guess the ultimate compliment is, about a year and a half into this there's a individual that attends every public meeting. And he belonged a anti-nuclear organization, mainly environmental.

And he came up to me and said, you know, Tony, he said, when you first started this 0350 stuff I thought you guys were just a rubber stamp. And you were just, you know, go through your motions and, you know, the plant would restart. He said, but after watching you guys for a year and a half, he goes, well, you're not a rubber stamp. You're really taking it to them. He said, you're, the details are the, you know, they're posted exactly what they're going to do.

The public meetings where sometimes we were challenging to OPPD on where they're at. And there's inspections that we did, that we had to do twice. Because the first time things didn't hit the mark. But that told me that the public had some confidence. At least this individual who didn't have much confidence in us did.

So, we're doing something right. But that's a very important piece of what we do. You can go to the next slide. The Manual Chapter states that after plant restarts that we would look at plant, that 0350 would stay in place for a nominal three quarters. And at that period of time you would look at how the site is performing. And there's some specific criteria that's been laid out.

And the four specific items are, is the licensee implementing an effective long range improvement plant program? Are they implementing the corrective action program? Are they demonstrating safe plant operation, and overall improvement performance? And are controls in place to address the plant's specific issues that resulted in increased oversight?

For the first one, yes, you know, we don't have major concerns with their long range improvement program. They are implementing it. They have had some areas where they've had to do what we call checks and adjust. You know, they had a plan. Maybe there, some adjustments needed to be done. They've done that. They're a living program.

Are they sufficiently implementing the corrective action program? That is the area that as an 0350 panel we are not comfortable with. And the corrective action program, somebody had mentioned this. It's more than just evaluation and resolution. You have identification, which actually Fort Calhoun are doing pretty good at it.

Prioritization, for the most case, pretty good at that. But then when you get in the evaluation of issues, based on the results and resolution, that piece, those pieces need to be shored up. And like we talked about before, it's really up to the licensee to fully understand why, you know, some of the challenges now. And then make the adjustments as need be to get that right.

And when they say that they've made adjustments, and they're ready for us to not just look at their plant, but to see a little bit of their performance, to actually see how the site is doing. And I think in this area it's the resident inspector's insights of seeing how issues are dealt with day in and day out, are going to be very important.

As well as, we're going to have a team, not 17 people probably, but smaller than that, to look at focus in that area. So, for us to be satisfied that area is in good shape.

And then the area of safe plant operation. Fort Calhoun has demonstrated that. We have seen a change from having some -- It's been around for a while. If you look at Fort Calhoun today, and the way they're operating, and before, you know, they were safe.

But I would say just from some of the things Mr. Cortopassi talked about. When they had equipment issues, they assessed it, you know. They were deliberate. And they made conservative decisions to place the plant in a safe condition. And that's, and we've seen this now on several occasions. So that's, I think they're doing well in that area.

And then the last, the plant specific issues that we talked about. They're still out there for long term resolution. They have plans for containment internal structures, for example. So, they're in pretty good shape there.

So, where it stands right now, three of these four criteria, based on the -- This could change tomorrow. But three of the four criteria, it looks like the Fort Calhoun station is doing well in.

But the corrective action piece is also very important, as like, when we started our discussion this morning, we talked about the reactor oversight process of transitioning Fort Calhoun, you know, what the, how the oversight process got Fort Calhoun to increase agency focus. Now they're getting ready to transition back.

The reactor oversight process, a very important piece of it is that a licensee has a program that they're implementing, that they self-identify issues and resolve those issues. And that's the corrective action program piece.

And the ROP is largely based on that principle and that program. And that's why we feel it's important that that area needs to be shored up prior to transitioning them back to the normal oversight process.

CHAIRMAN SKILLMAN: Tony, when does that third quarter come to an end?

MR. VEGEL: It just did yesterday.

CHAIRMAN SKILLMAN: Oh, it did?

MR. VEGEL: Yes, sir. Yes. But we were looking whether it had to be. But about three quarters of operation. And that's why we did the problem identification resolution inspection with 17 people. Because they basically looked at this criteria. And looked at that last inspection, as well as the last previous nine months of inspections as well.

CHAIRMAN SKILLMAN: Thank you.

MR. VEGEL: You're welcome. So, with that I guess we're, I think we're ahead of schedule, if you don't mind.

(Off microphone comment)

MR. VEGEL: I'd like to summarize the Manual Chapter 0350 process. I believe it's an effective tool. I think when a licensee, you know, performance warrants increased agency oversight. But the true learnings I think for us on, from an 0350 perspective we've gotten some lessons learned, and things that we want to capture, some good practices that we did.

But then too, I think there's an opportunity for us to learn about the whole Fort Calhoun experience, in that the reactor oversight process worked, in that it identified performance issues, the whites, the yellows, and eventually the reds, and got the agency oversight.

But too, I think there's some learnings to be had. Like why we could have probably done better in those areas. And I think we've also captured some of that as well as part of our activity. So, I think that in the future I think we'll be hopefully better served. And hopefully 0350 will continue to be a infrequently used procedure. So, with that, thank you very much.

CHAIRMAN SKILLMAN: Thank you.

MR. VEGEL: Any other questions for us?

CHAIRMAN SKILLMAN: Let me ask my colleagues. Around the table, any members with questions, around the table?

(Off microphone comment)

CHAIRMAN SKILLMAN: Steve, Harold?

MEMBER RAY: Well, I guess I would just offer, the circumstances relating to Fort Calhoun I think ought to be of less, I'll say not interest but concern, than would be what lessons the agency draws from the experience. And I don't really hear a lot about that here. Because it's mostly focused on Fort Calhoun.

Remember, I think, you know, that's been put under a microscope for long enough. I don't think we could add anything to it. But the real question I think comes about, as the agency would expect licensees to do, what do we learn from this about everything else we do? That's what we ought to be focused on, I think, not so much what have they wrung out of Fort Calhoun.

(Off microphone comment)

CHAIRMAN SKILLMAN: Thank you, Harold. Dr. Powers.

MEMBER POWERS: I just admire the point that Harold made.

CHAIRMAN SKILLMAN: Thank you. Mr. Chairman, sir, any comments?

MEMBER STETKAR: Nothing, sir.

CHAIRMAN SKILLMAN: I would like to ask if the bridge line is open, please? Mark, are we open? While Mark is checking that, any member of the audience that would make a comment today?

(Off microphone comment)

CHAIRMAN SKILLMAN: Hearing none, let's check the phone line here.

(Off microphone comments.)

CHAIRMAN SKILLMAN: No one on the bridge line. Let me just make a couple of comments. I would like to thank each of you that prepared homework, and traveled and came here today. I would like to thank Jody from the Corps of Engineers, Farhat, Thank you very much for your presentation. Louise, you and your team, thank you. And Mike and Tony, thank you very much.

MR. HAY: You're welcome.

CHAIRMAN SKILLMAN: And with that, we are adjourned.

(Whereupon, the above-entitled matter went off the record at 2:29 p.m.)

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

ACRS Briefing of Fort Calhoun Station Performance and NRC Oversight Activities

Tony Vegel – 0350 Panel Chair/RIV

Louise Lund – 0350 Vice-Chair/NRR

Mike Hay - Branch Chief, DRP/RIV

Reactor Oversight Process (ROP)

- Inspects, measures, and assesses the safety performance of nuclear power plants and respond to any decline in performance. Measured and assessed by a combination of objective performance indicators reported by the licensee and by NRC inspection findings. Focuses on reactor safety, radiation safety, and safeguards which are broken down into seven cornerstones:
  - Initiating Events
  - Mitigating Systems
  - Barrier Integrity
  - Emergency Preparedness
  - Occupational Radiation Safety
  - Public Radiation Safety
  - Security

- The significance or color is determined using the Significance Determination Process, which uses risk insights to assist the staff in determining the safety or security significance of inspection findings.

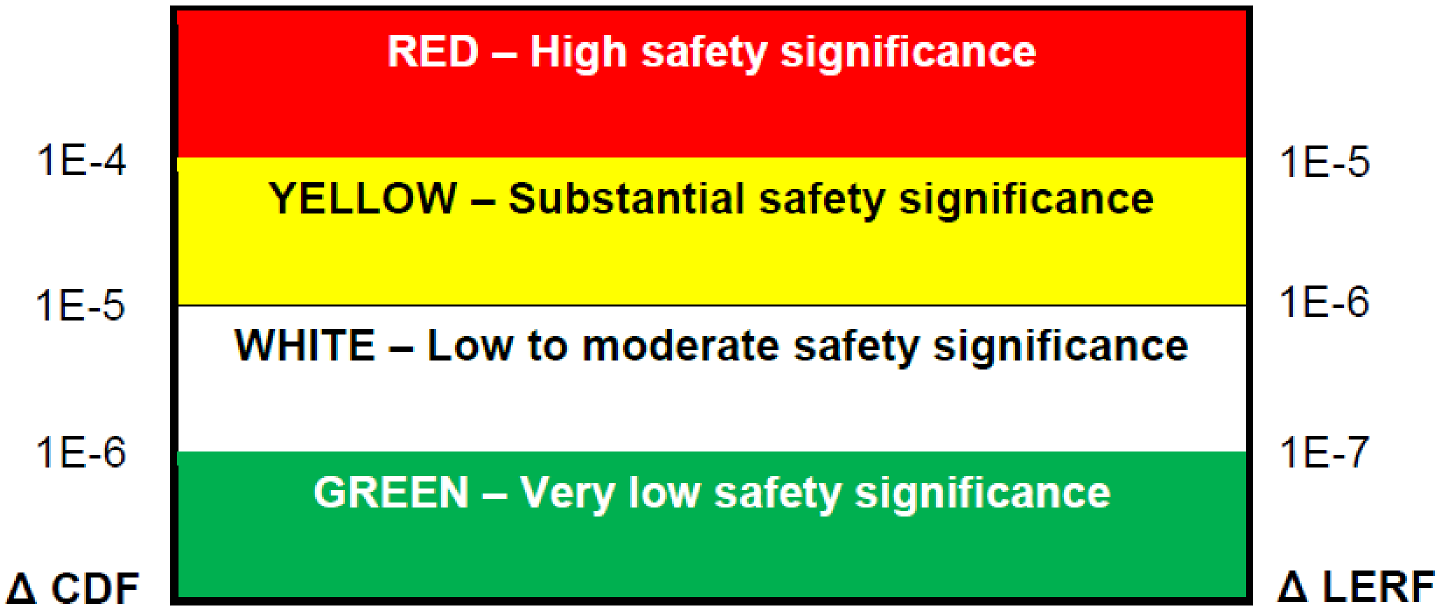


Figure 1 Graphical Representation of Quantitative Significance of Findings

Significance of Findings

- Qualitatively, the four significance categories indicate the following:
  - **RED – High safety significance**
  - **YELLOW – Substantial safety significance**
  - **WHITE – Low to moderate safety significance**
  - **GREEN – Very low safety significance**

ROP Action Matrix

Increasing Safety Significance

ROP Action Matrix Asessment of Plant Performance	NRC Response
Column 5. Unacceptable Performance	**Response at Agency Level**
Column 4. Multiple/Repetitive Degraded Cornerstone Repetitive degraded cornerstone, multiple degraded cornerstones, or multiple **YELLOW** inputs, or one **RED** input	**Response at Agency Level** • Meeting with NRC Executive Director for Operations and senior plant management • Plant operator improvement plan with NRC oversight • NRC team inspection focused on performance issues at the site • Demand for Information, Confirmatory Action Letter, or Order
Column 3. Degraded Cornerstone One degraded cornerstone (two **WHITE** inputs or one **YELLOW** input or three **WHITE** inputs in any strategic area)	**Response at Regional Level** • Meeting with NRC regional management and senior plant management • Plant operator self-assessment with NRC oversight • Additional NRC inspections focused on cause of degraded performance
Column 2. Regulatory Response No more than two **WHITE** inputs in different cornerstones	**Response at Regional Level** • Meeting with NRC and plant management • Plant operator corrective actions to address WHITE inputs • NRC inspection to follow up on WHITE inputs and corrective actions
Column 1. Licensee Response All performance indicators and cornerstone inspection findings **GREEN**	**Normal Regional Oversight** • Routine inspector and staff interaction • Baseline inspection program • Annual assessment public meeting

Increasing Regulatory Oversight

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Inspection Manual Chapter (IMC) 0350 Process

- **Oversight of reactor facilities in a shutdown condition due to significant performance and/or operational concerns**

IMC 0350 Implementation

- **Initiated December 2011**
- **Coordinated extensive oversight activities**
  - **Restart Authorized December 2013**
  - **IMC 0350 oversight continues – Post Restart**

Missouri River Basin Water Management

Advisory Committee on Reactor Safeguards
Nuclear Regulatory Commission

Regarding Fort Calhoun Station

Rockville, Maryland
October 1, 2014

Jody Farhat, P.E.
Chief, Missouri River Basin Water Management

US Army Corps of Engineers
BUILDING STRONG®

Topics

- Corps of Engineers Organizational Structure
- Overview of Missouri River Basin Water Management
- Corps' Emergency Management "Flood Fight" Protocols

US Army Corps of Engineers (USACE)

Northwestern Division

Missouri River Basin Water Management

Where does Missouri River Basin Water Management fit into the Corps of Engineers?

- Administration
  - Department of Defense
    - Department of the Army
      - Headquarters USACE
        - ***Divisions***
          - Districts

Missouri River Basin Water Management Staffing

Total employees = 12

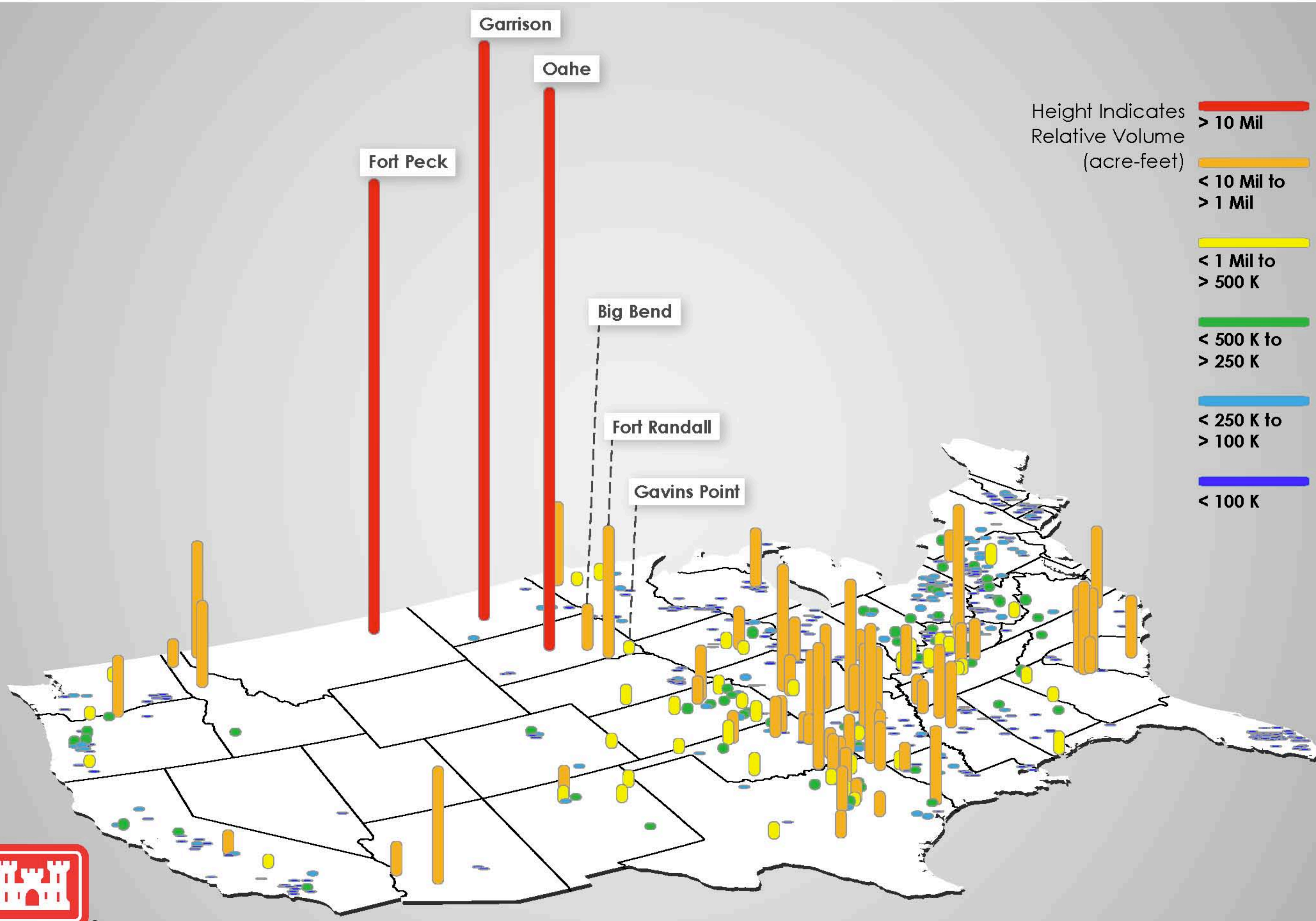
- 8 Engineers
- 1 Fishery Biologist
- 2 IT specialist
- 1 Secretary

Missouri River Mainstem Reservoir System

Congressionally Authorized
Project Purposes
- Flood Control
- Navigation
- Hydropower
- Irrigation
- Recreation
- Water Supply
- Water Quality
- Fish and Wildlife
  (Including endangered species)

Bank Stabilization and Navigation Project
Sioux City, IA – St. Louis, MO

Storage Capacity of Corps Reservoirs

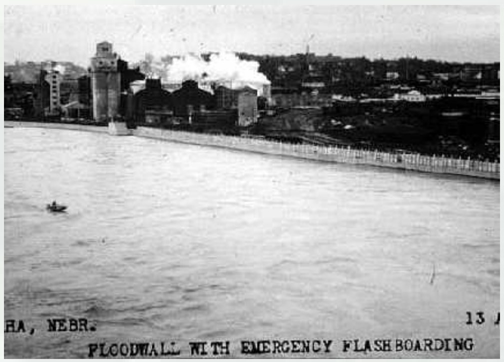


Prepared and Produced by the U.S. Army Corps of Engineers Omaha District 2010

Our Mission

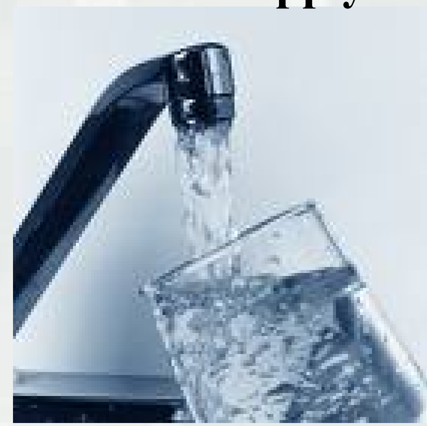
Regulate Missouri River Mainstem Reservoirs to Support Congressionally Authorized Purposes

Flood Control



Hydropower

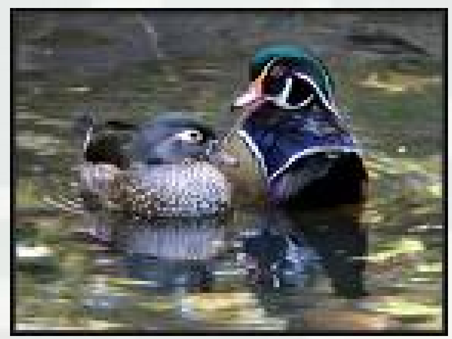
Water Supply



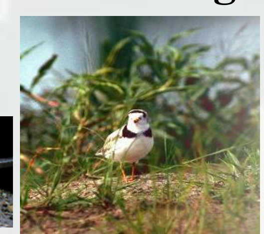
Water Quality Control

Recreation

Navigation

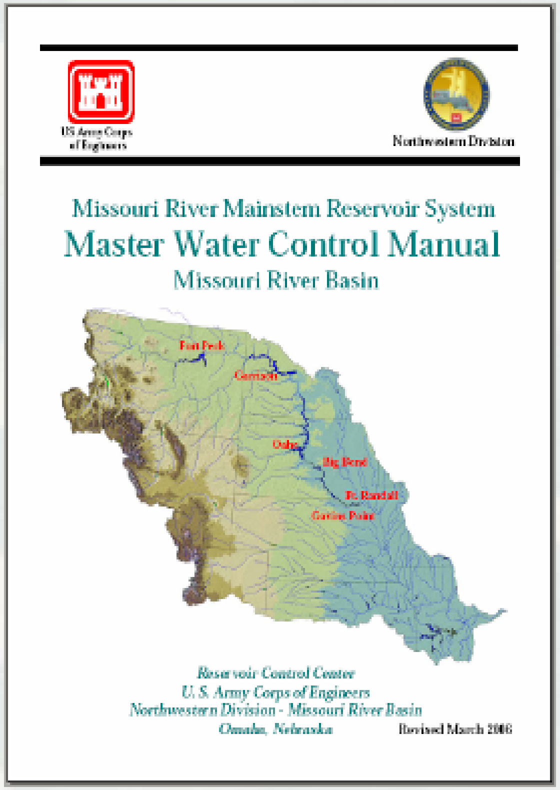


Fish and Wildlife Including Threatened and Endangered Species



Irrigation

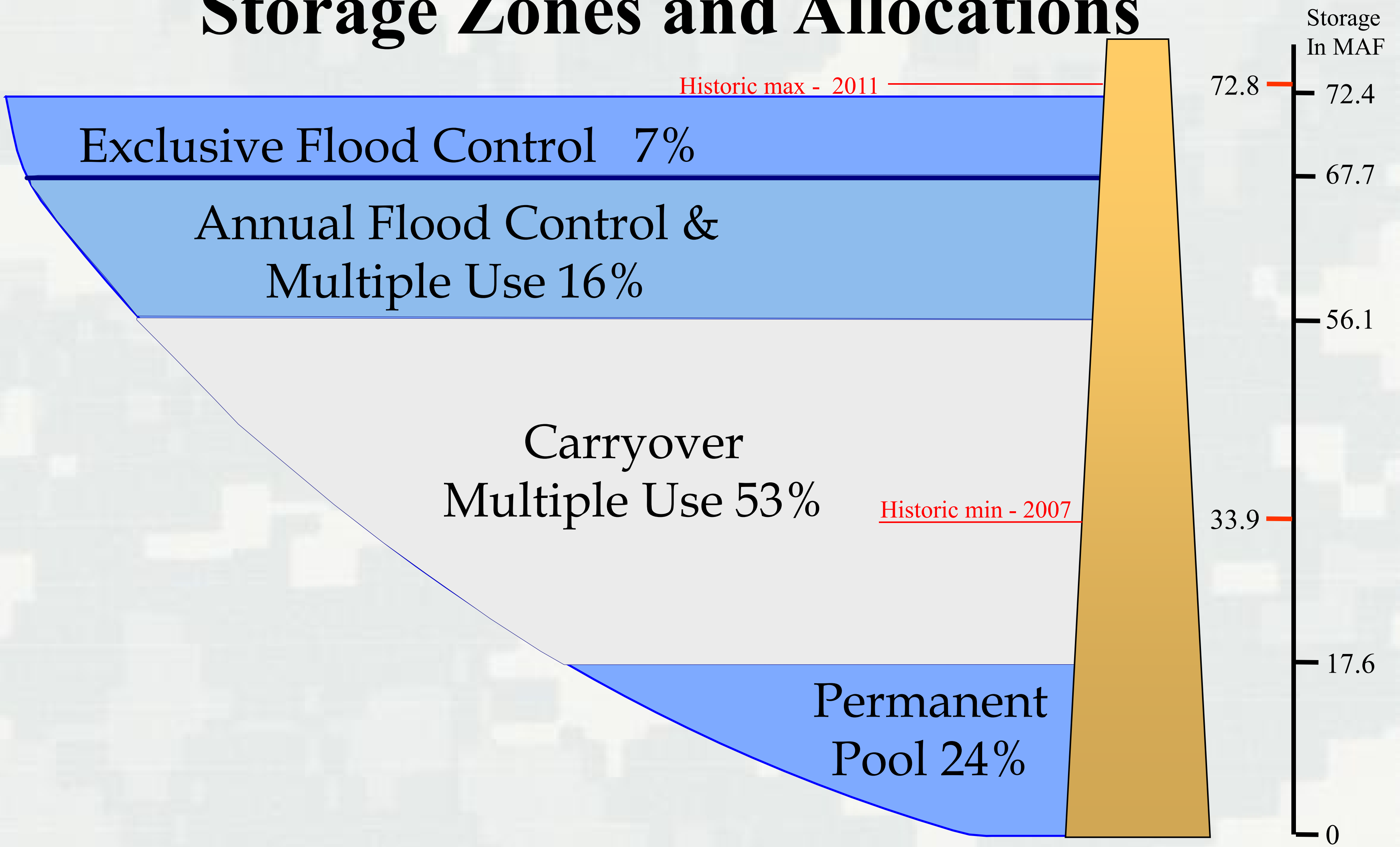
Missouri River Mainstem Reservoir System Master Manual


Missouri River Mainstem Reservoir System
Master Water Control Manual
Missouri River Basin

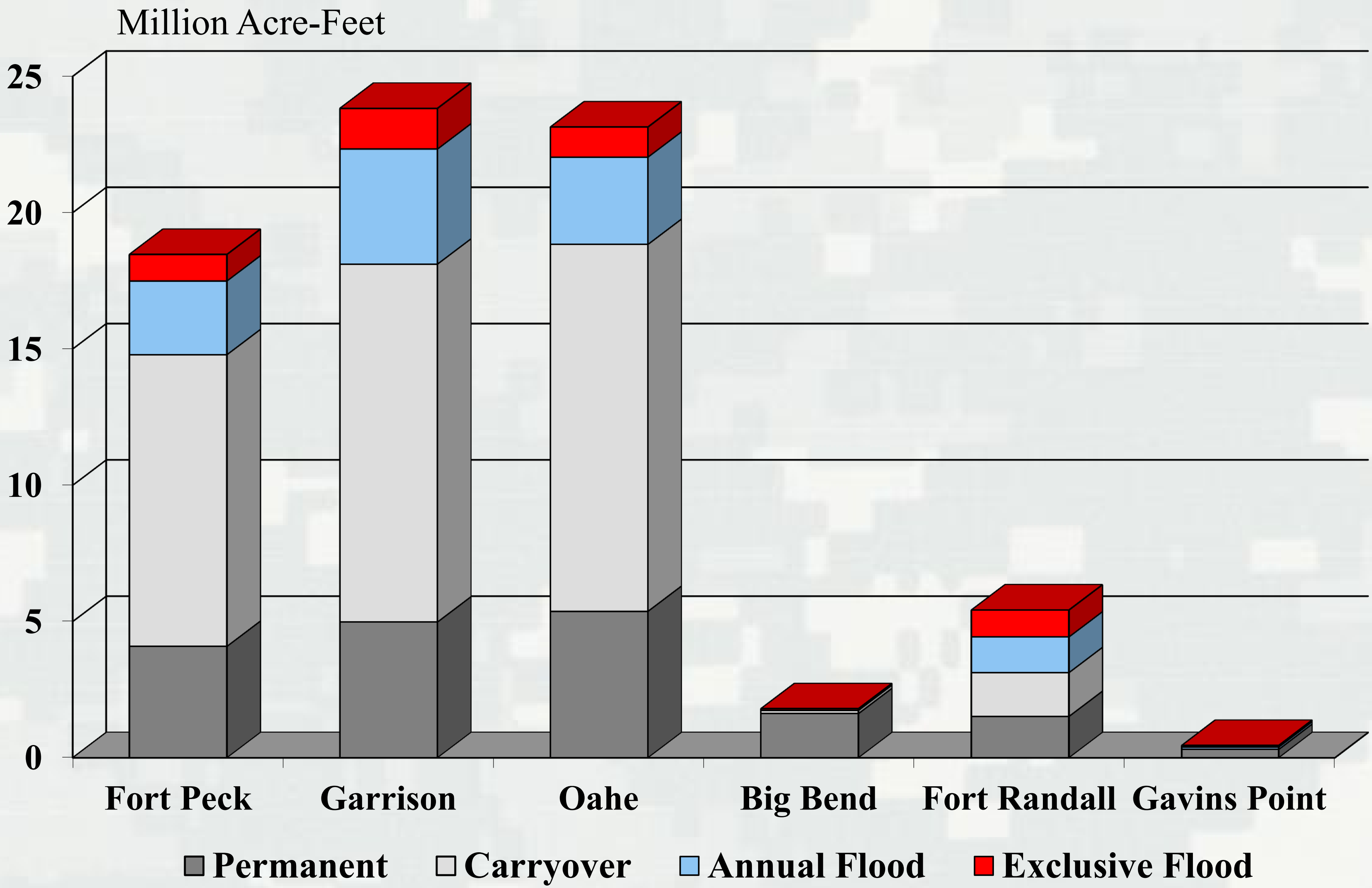
Reservoir Control Center
U. S. Army Corps of Engineers
Northwestern Division - Missouri River Basin
Omaha, Nebraska
Revised March 2006

- First published in 1960
- Updated in 1975 and 1979
- Master Manual Review and Update began in November 1989 in response to late 1980's / early 1990's drought
- Amended Biological Opinion received from USFWS in December 2003
- Master Manual was revised for drought conservation in March 2004
- Revised again in March 2006 for Gavins Point spring pulse
- Annual Operating Plan (AOP) developed annually in accordance with Master Manual

Missouri River Mainstem System Storage Zones and Allocations



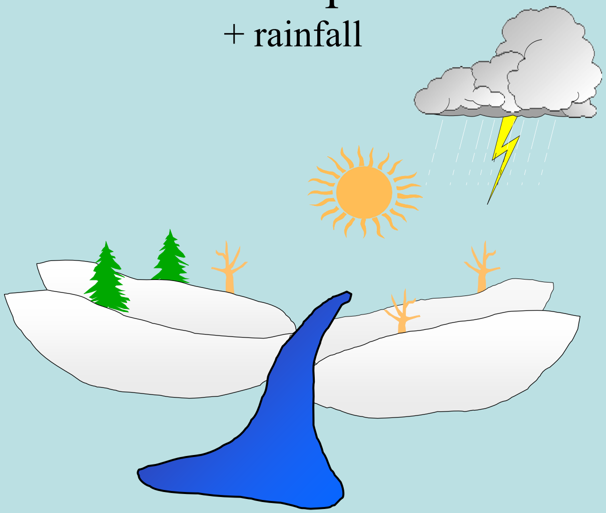
Mainstem Reservoir Storage Capacity



Runoff Components

Plains Snowpack

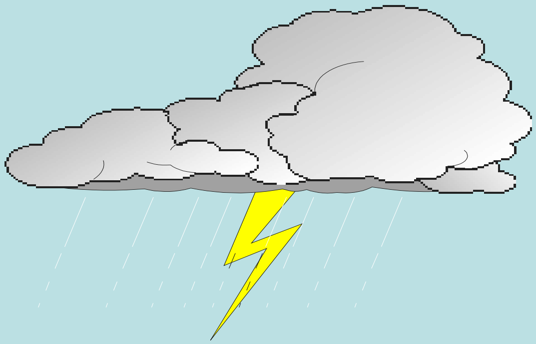
+ rainfall



Mountain Snowpack

+ rainfall

Rainfall



March and April

~ 25% annual runoff

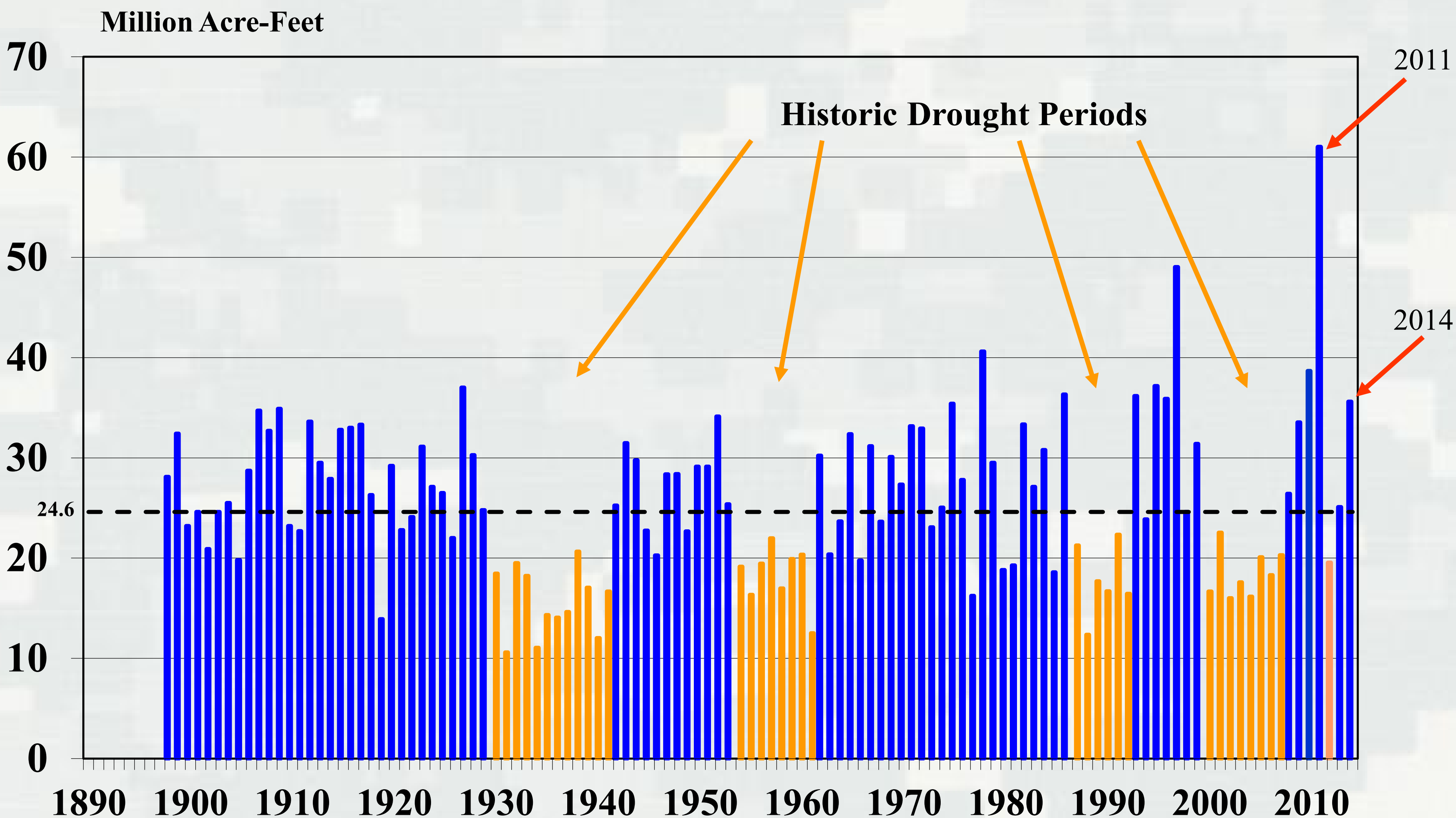
May, June and July

~ 50% annual runoff

March through October

Average Annual Runoff ~ 25 MAF

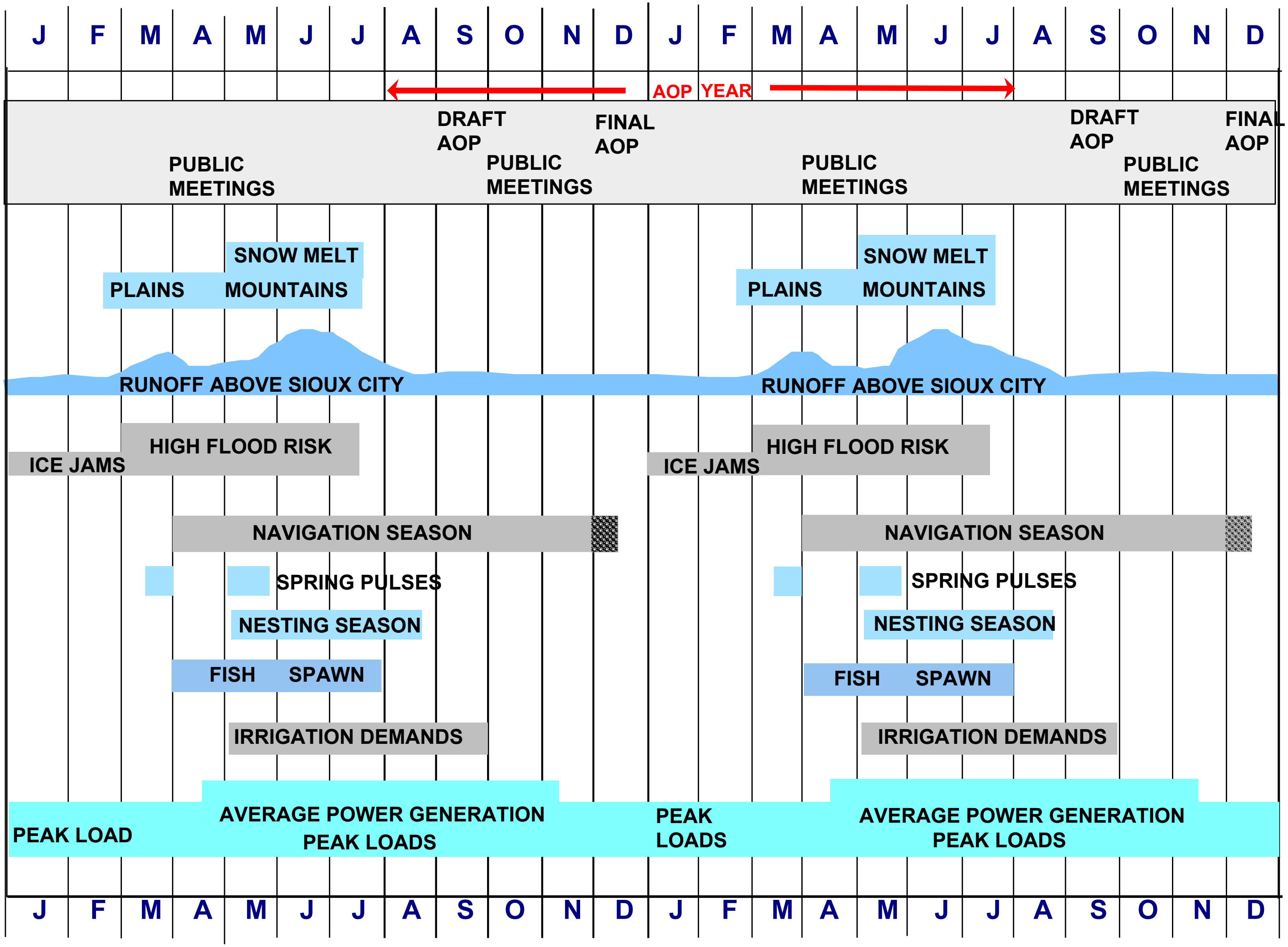
Missouri River Mainstem System Annual Runoff above Sioux City, IA



Reservoir Regulation during Extreme Events

- Flexibility built into Mainstem Reservoir System
  - Reservoir system designed for extreme floods and extended droughts
  - Master Manual provides seamless transition between droughts and floods
  - Operations tweaked over the years to meet new requirements such as the Endangered Species Act and Clean Water Act, but the Missouri River remains a runoff driven system
- Changing conditions on the ground
  - Infrastructure has developed around our projects
    - Municipal and industrial water intakes
    - Recreation facilities
    - Encroachment into flood plain
  - River channel continues to evolve
- Changing Climate
  - Potential to spend more time on both ends of the hydrologic spectrum

Calendar of Events



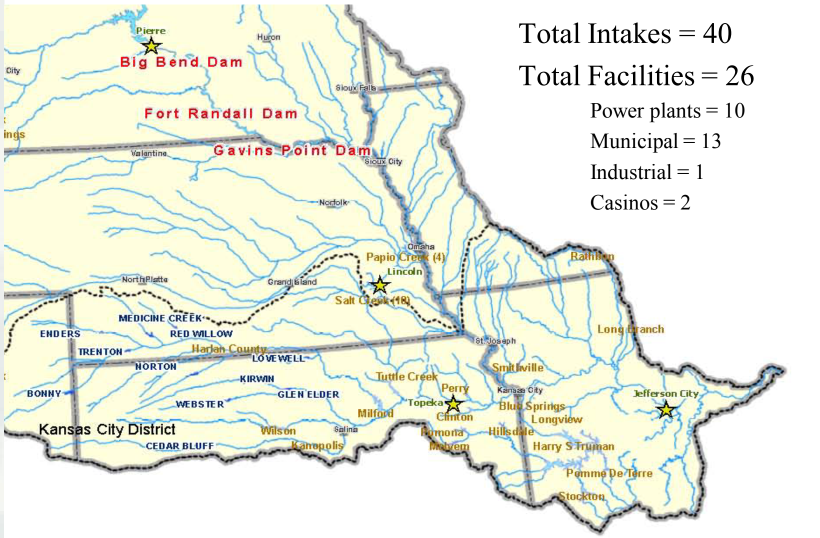
Flood Control

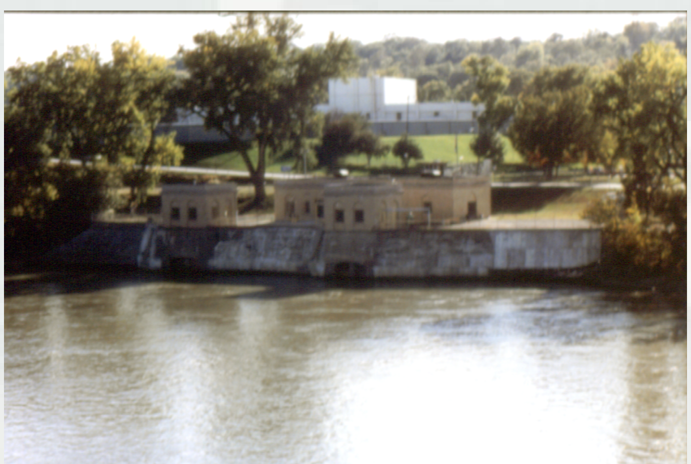
Council Bluffs, Iowa
Summer 2011

- Requires empty space in reservoirs
- Water captured during high runoff events and metered out through remainder of the year to serve authorized project purposes
- Evacuate all stored flood water by start of next year's runoff season (1 March)
- Provides significant flood damage reduction, but cannot eliminate all flooding (unregulated runoff)
- Ability to reduce downstream stages depends on timing of peak and distance from control point

Water Supply

Major Lower Missouri River Intakes

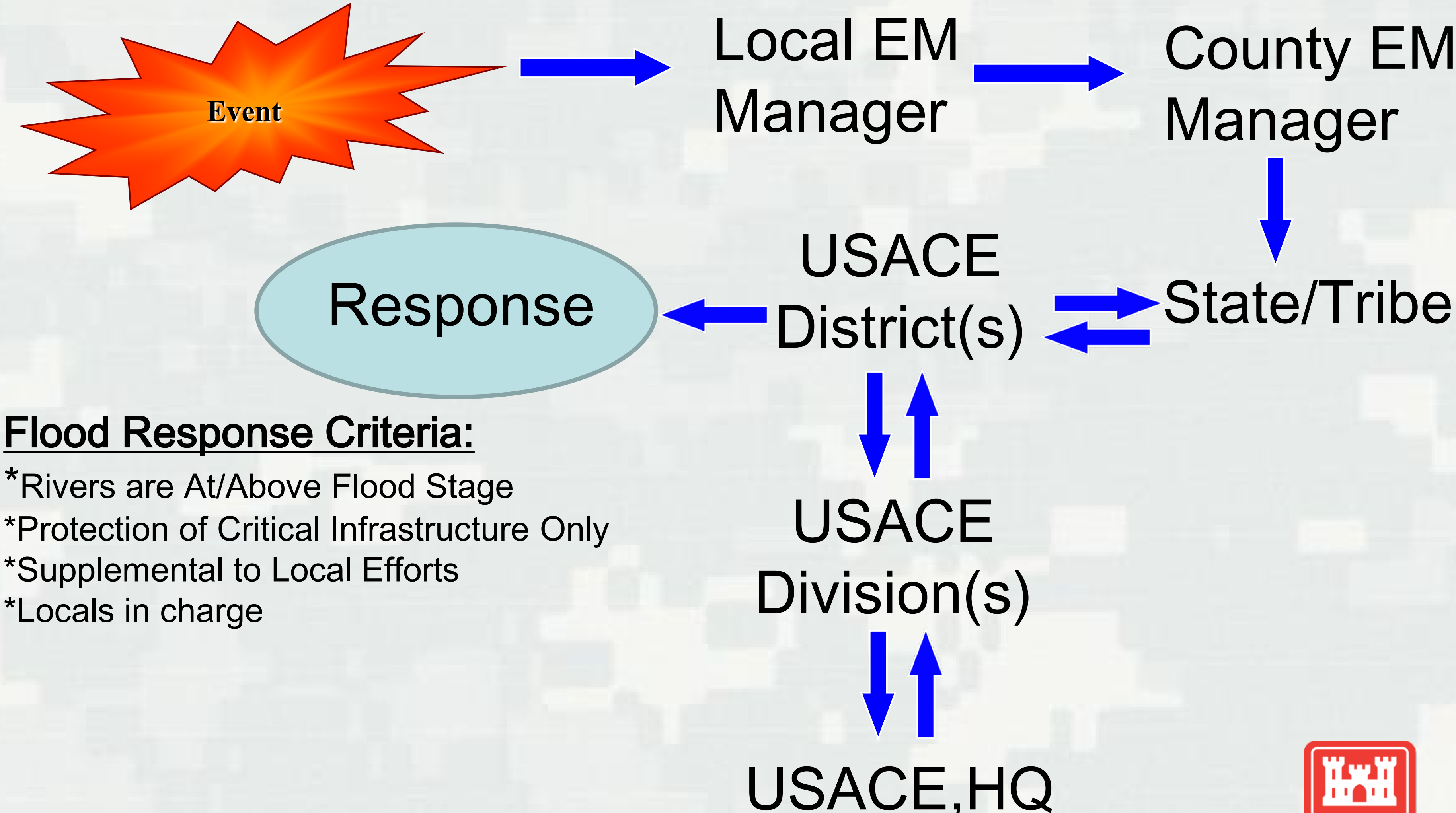




- Intakes require access to water
  - Always sufficient water in the river or reservoirs
  - Maintaining access to the water in the intake owner's responsibility
- Intake locations
  - On the reservoirs
  - On the river reaches between the reservoirs
  - On the river below the reservoir system
- Access affected by
  - Low reservoir levels or releases
  - Too much water (high pools or high downstream stages)
  - Ice jams

USACE PL 84-99 Flood Fight:

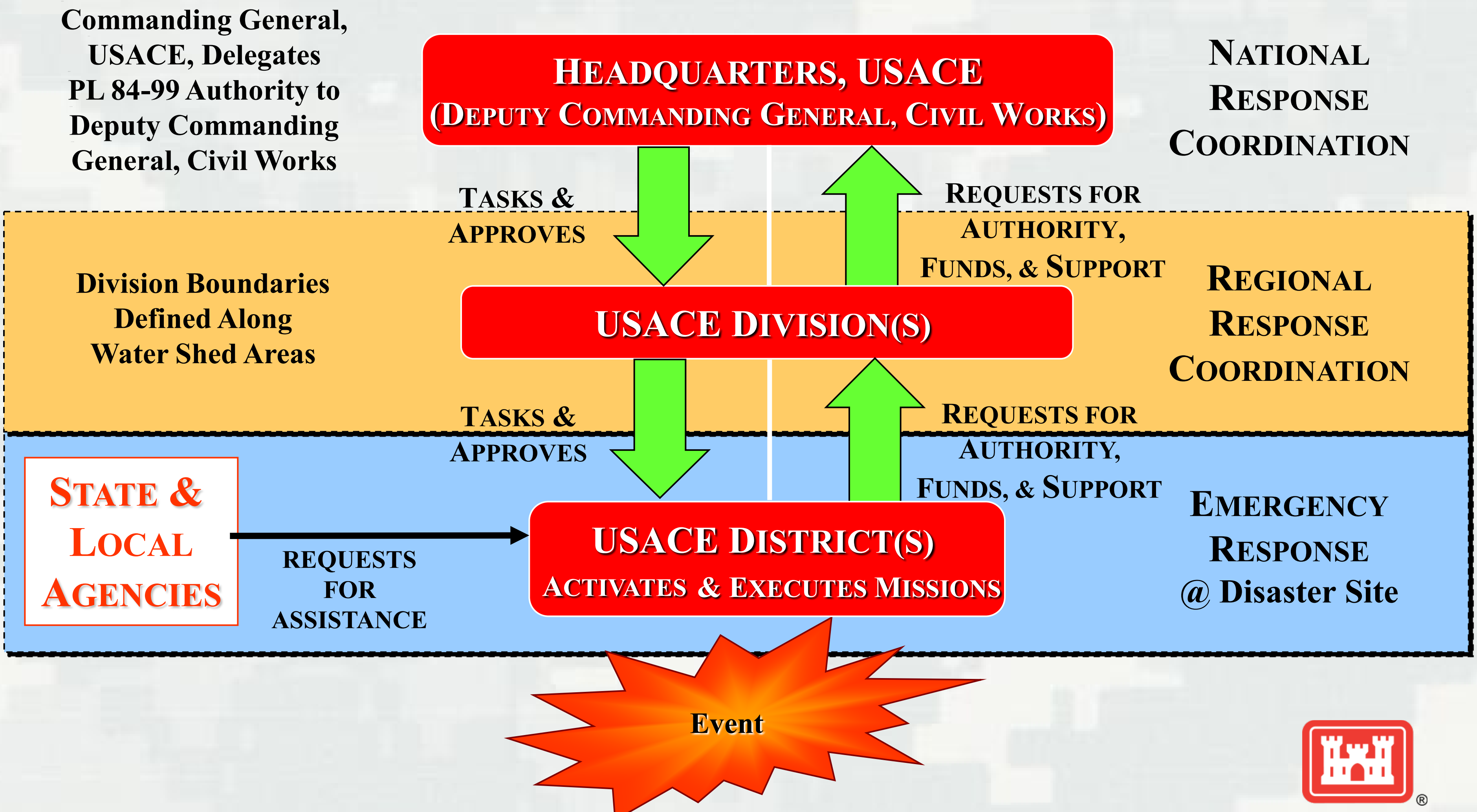
Activation of Federal Resources



Flood Response Criteria:

*Rivers are At/Above Flood Stage
*Protection of Critical Infrastructure Only
*Supplemental to Local Efforts
*Locals in charge

USACE Doctrine – PL 84-99
"The Flood Fight"



A Pre-Existing Architecture for Deliberate, Timely Response

Thank You!

Jody Farhat, P.E.
402.996.3840
jody.s.farhat@usace.army.mil

http://www.nwd-mr.usace.army.mil/rcc/
Or Google “Corps Missouri River”

BUILDING STRONG®

OPPD's Fort Calhoun Station

Driving to Excellence

Advisory Committee on Reactor Safeguards – Oct. 1, 2014

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Omaha Public Power District

Topics for Discussion

- NRC Special Oversight Timeline
  - 2011 Missouri River Flood
  - Electrical Bus Fire
  - Flood Recovery Confirmatory Action Letter (CAL)
  - Manual Chapter 0350 and Restart CAL
  - Operating Services Agreement with Exelon
  - CAL Closure and Restart
- Supporting Actions
  - Fukushima Response Project
  - Beyond Design Basis Flood Mitigation
  - Tornado-Borne Missile Protection
  - Containment Penetrations & Internal Structures
  - Security Upgrades
- Recent Events and the Way Forward
  - 2014 High-Water Event
  - Problem Identification & Resolution Inspections
  - Design and Licensing Basis Control and Use
- Closing Remarks

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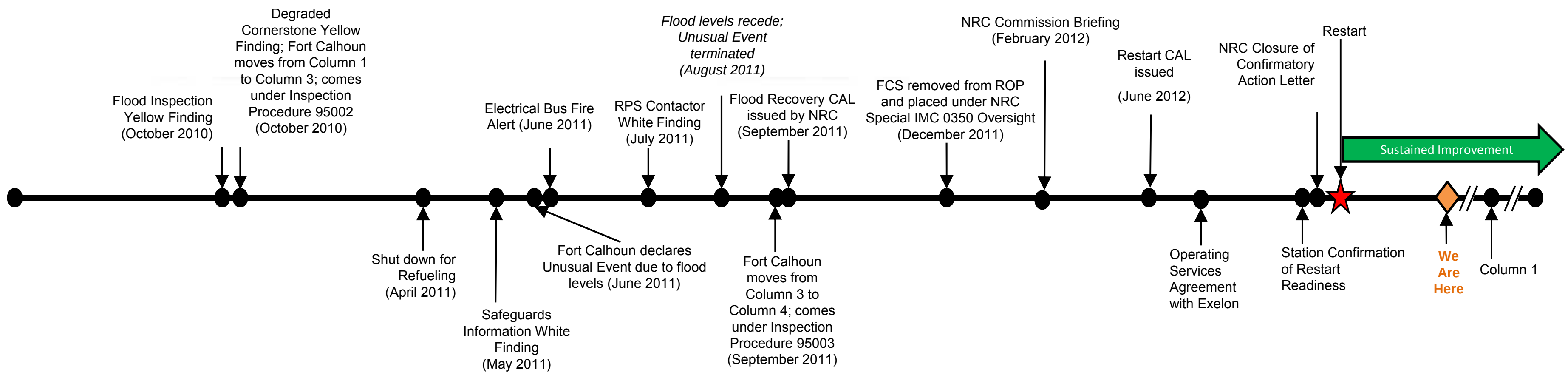
Timeline



- High-level review of key events from before and after NRC Inspection Manual Chapter 0350 oversight
- Other items and events included to provide context

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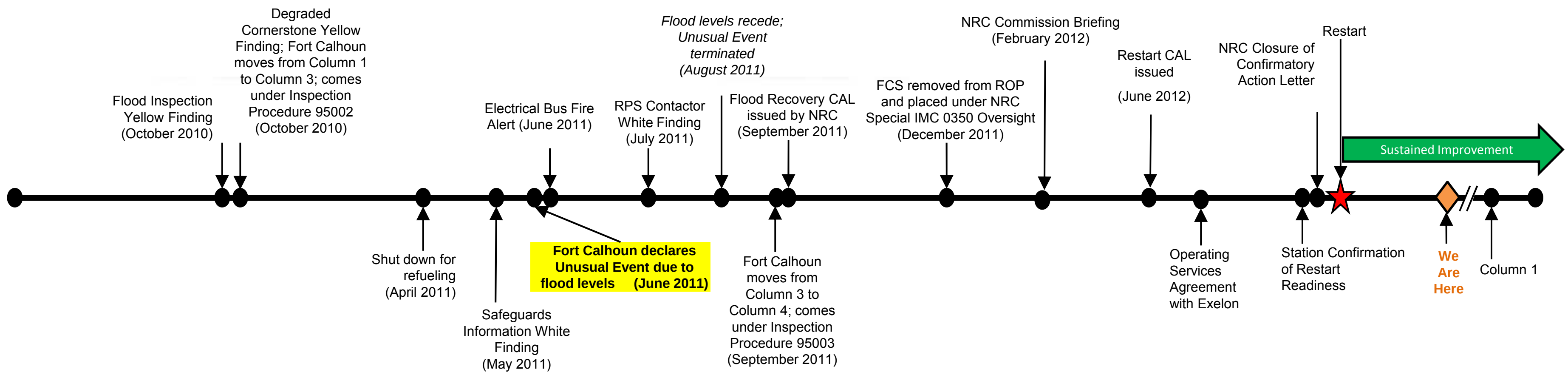
Timeline



- **Fort Calhoun declares Unusual Event due to flood levels (June 2011)**
- Seasonal flood rather than runoff flood
- Nearing the end of a refueling outage, opted to remain offline
- Exceeded 1,004’ shutdown level
- Flood crested at 1,007’ msl
- Design basis: 1,014’

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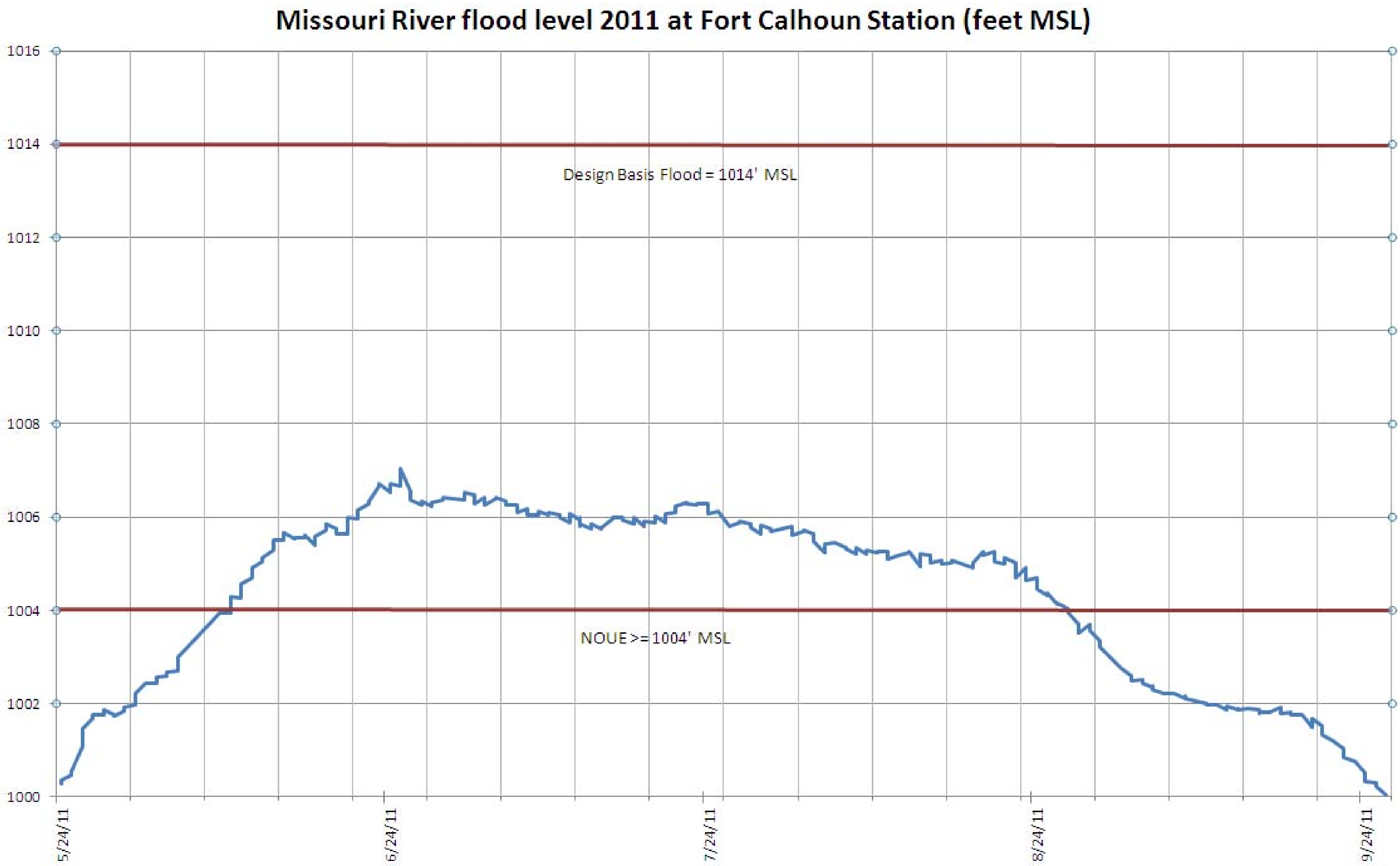

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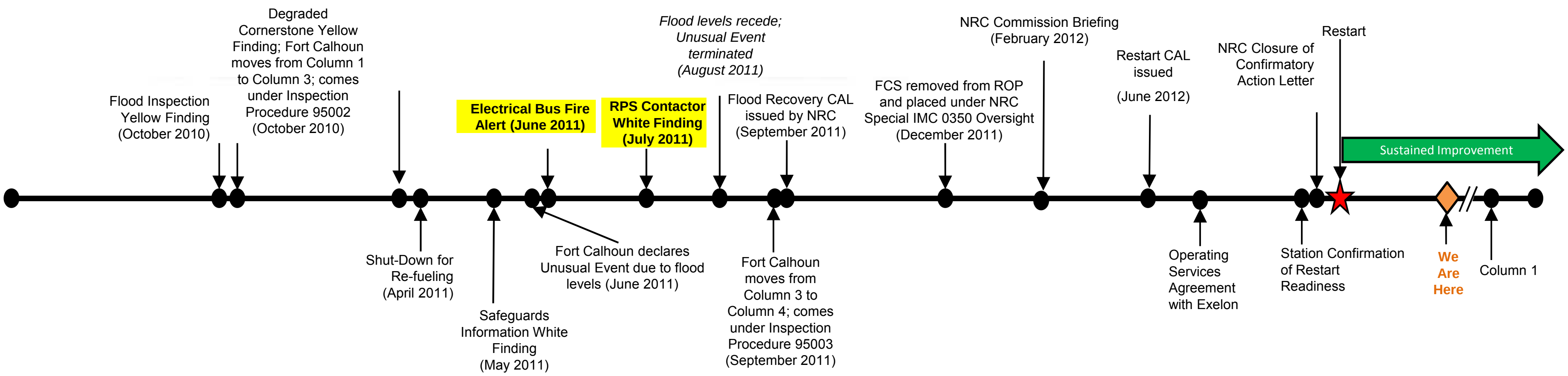
Timeline



- **Electrical Bus Fire Alert (June 2011)**
- Reactor Protection System M2 contactor failure
- 480 volt AC switchgear
- **RPS Contactor White Finding (July 2011)**

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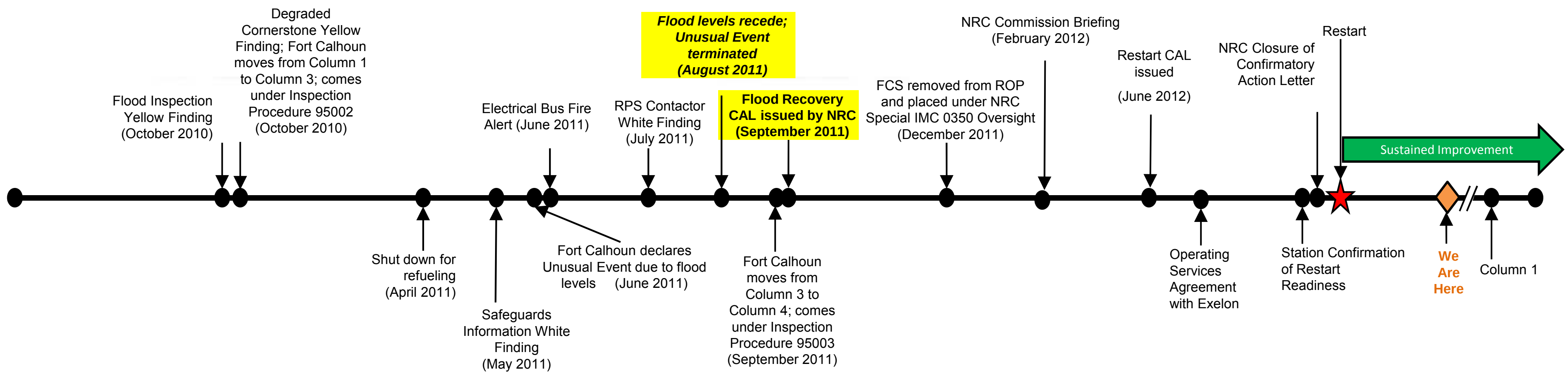
Electrical Bus Replacement

Damaged 1B4A Cubicle

Restored Switchgear 1B4A

Timeline



- **Flood levels recede; Unusual Event terminated (August 2011)**
- **Flood Recovery CAL (Confirmatory Action Letter) issued by NRC (September 2011)**

Flooding Recovery Action Plans

- Developed 17 flooding recovery action plans, grouped by focus area

- These plans detailed a total of more than 360 individual action items

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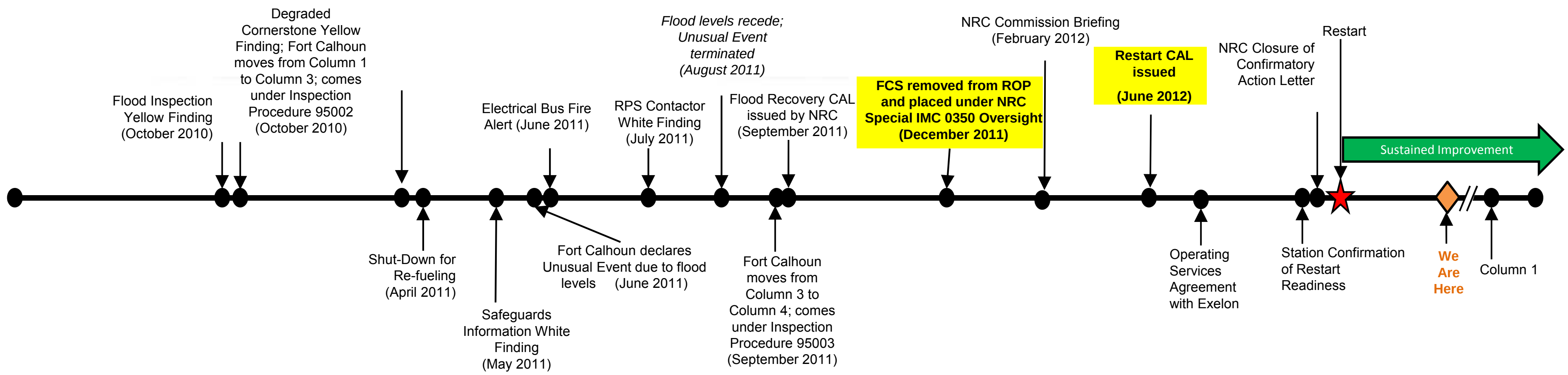
Timeline



- **FCS removed from ROP (Reactor Oversight Process) and placed under NRC Special IMC (Inspection Manual Chapter) 0350 Oversight (December 2011)**
- **Restart CAL Issued (June 2012)**
- CAL updated February 2013

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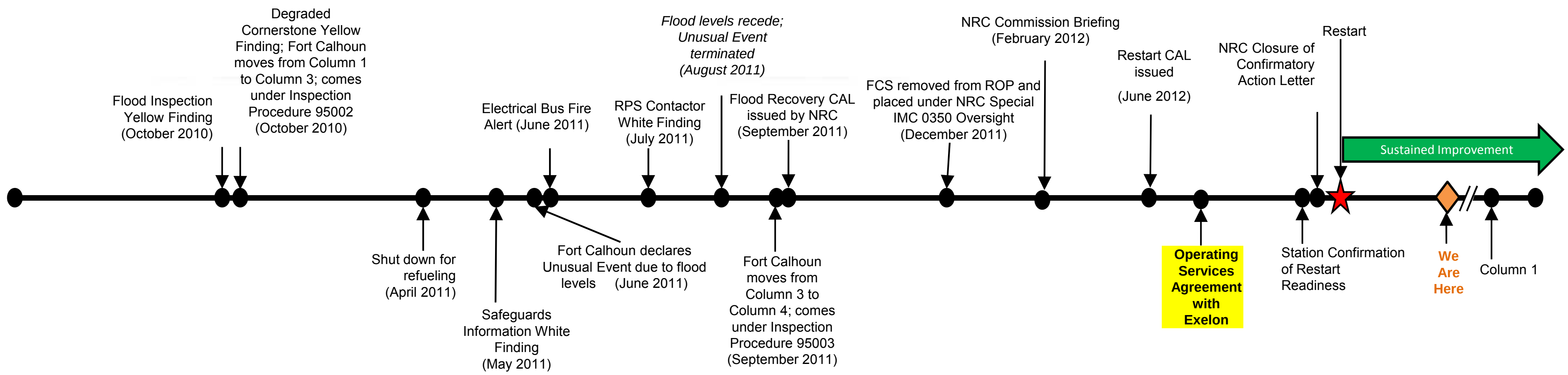
Manual Chapter 0350 & Restart CAL

Restart Checklist Item	Issue Description
1.a	Flooding Issue
1.b	Reactor Contactor Failure
1.c	Electrical Bus Mod and Maintenance
1.d	Security Issue
1.e	Safety Culture
1.f	Organizational Effectiveness
1.g	Safety System Performance Indicator
2.a	Flood Recovery Restoration Actions
2.b.1	System Health Reviews
2.b.2	Reactor Safety Strategic Performance Area Review
2.b.3	Flood Impact on Soils and Structures
2.b.4	Containment Penetration Design
2.b.5	Containment Internal Structure Design

Manual Chapter 0350 & Restart CAL

Restart Checklist Item	Issue Description
3.a	Corrective Action Program
3.a.1	Identification, Analysis and Correction of Performance Deficiencies
3.b.1	Safety Related Parts
3.b.2	Equipment Qualification
3.c.1	Vendor Modifications
3.c.2	10CFR50.59 Screening and Safety Evaluations
3.d.1	Vendor Manuals
3.d.2	Equipment Service Life
3.e.1	Operability Determinations
3.e.2	Degraded / Non-Conforming Equipment
3.f	Quality Assurance

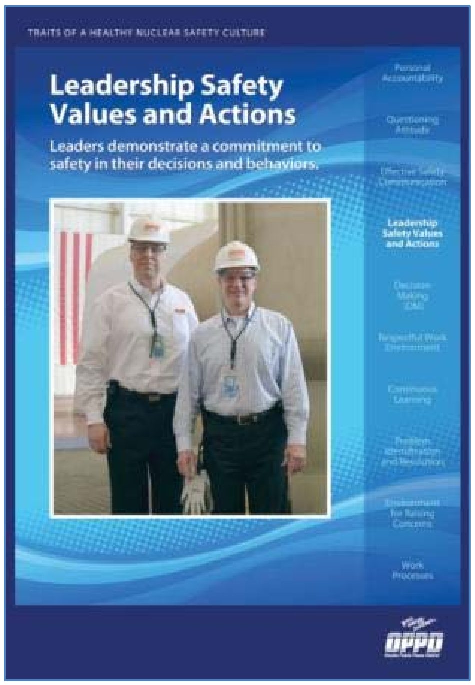
Timeline



- **Operating Services Agreement with Exelon**
- 20-year contract through 2033, end of current operating license

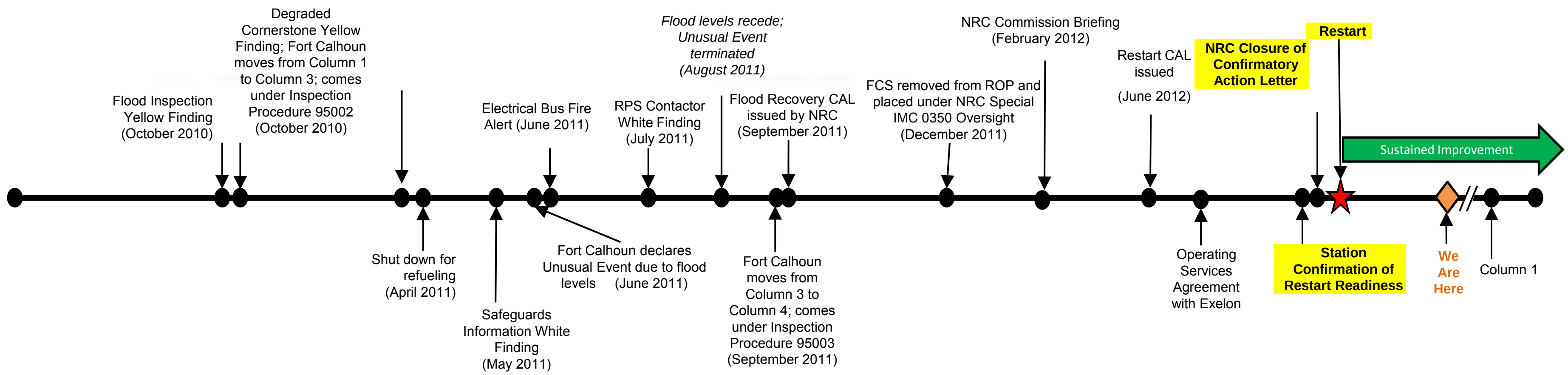
The Exelon Nuclear Management Model

- The comprehensive Exelon Nuclear Management Model (ENMM) contains all necessary policies, programs and procedures, but its success is driven by:



  - **Strong and intrusive leadership team**
  - **Passion for excellence**
  - **Effective independent oversight**
- Excellence will be cemented by full implementation of the ENMM and integration into the Exelon fleet
- Record of proven performance, demonstrated at other units
- FCS is enhancing, and is being enhanced by, the fleet

Timeline



- **Station Confirmation of Restart Readiness**
- **NRC Closure of Restart Confirmatory Action Letter**
- **Restart**
- Authorization came Dec. 17 – FCS went critical, connected to the grid and reached full power Dec. 26, 2013

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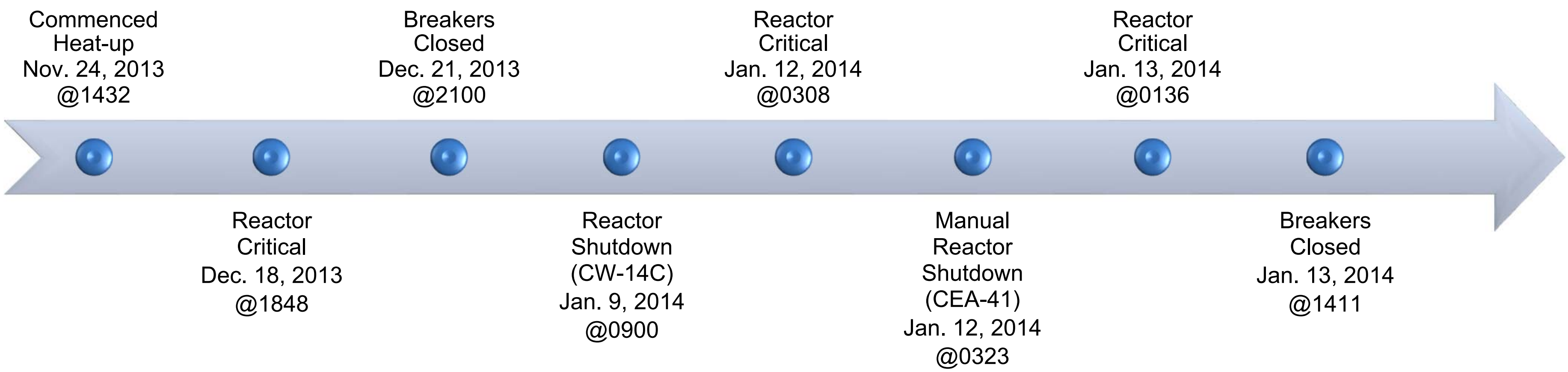
Site Operational Focus

- Fort Calhoun has resumed safe operations



1. Heat-up performed to support testing and equipment verifications
2. Reactor startup only after conditions confirmed and commitments met
3. Unit returned to service
4. Forced outage to repair river sluice gate
5. Control rod issue identified during unit startup; unit shut down to support repairs
6. Reactor restarted after repairs made and returned to service

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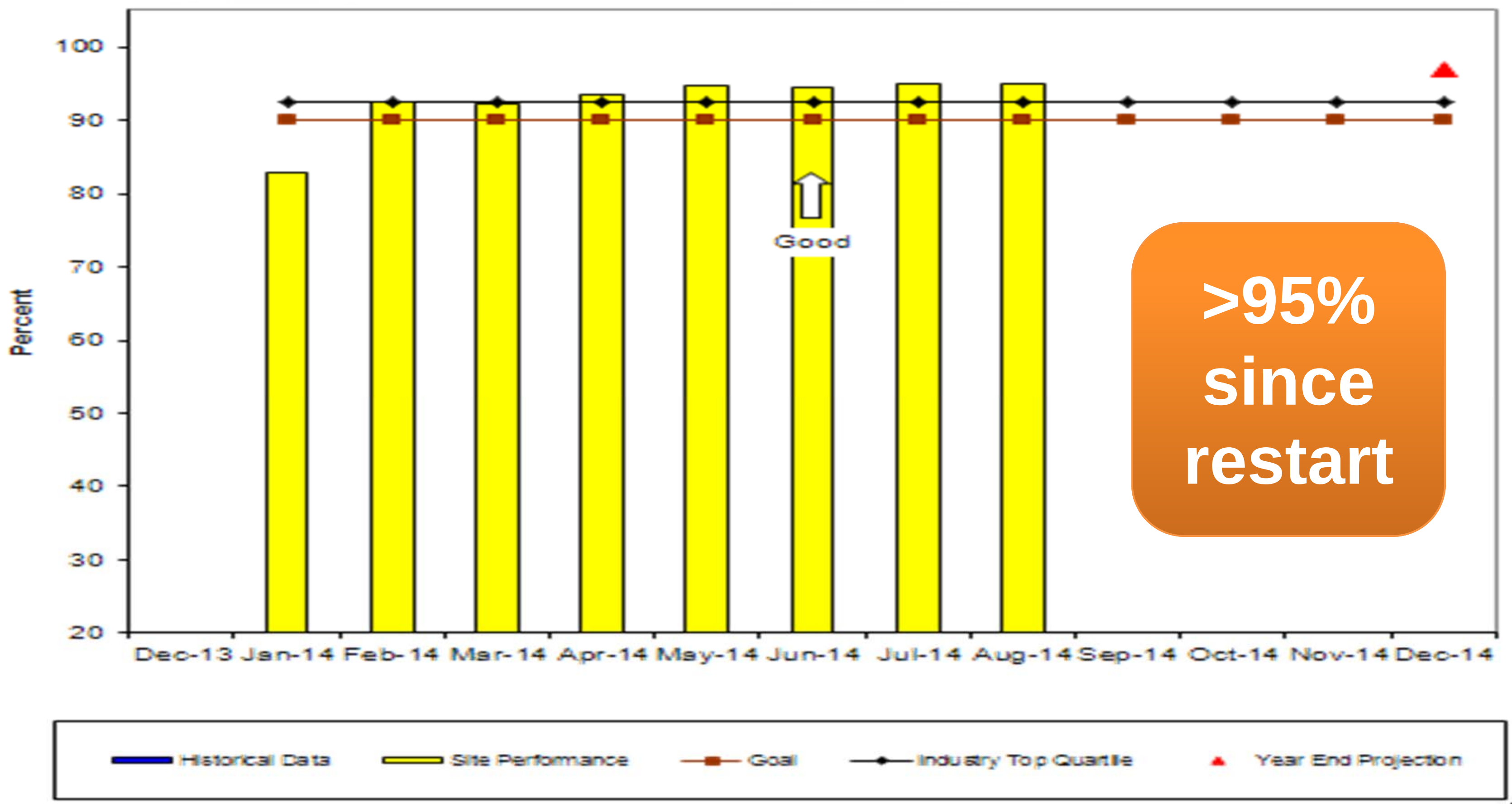
Plant Status

Cumulative Capacity Factor



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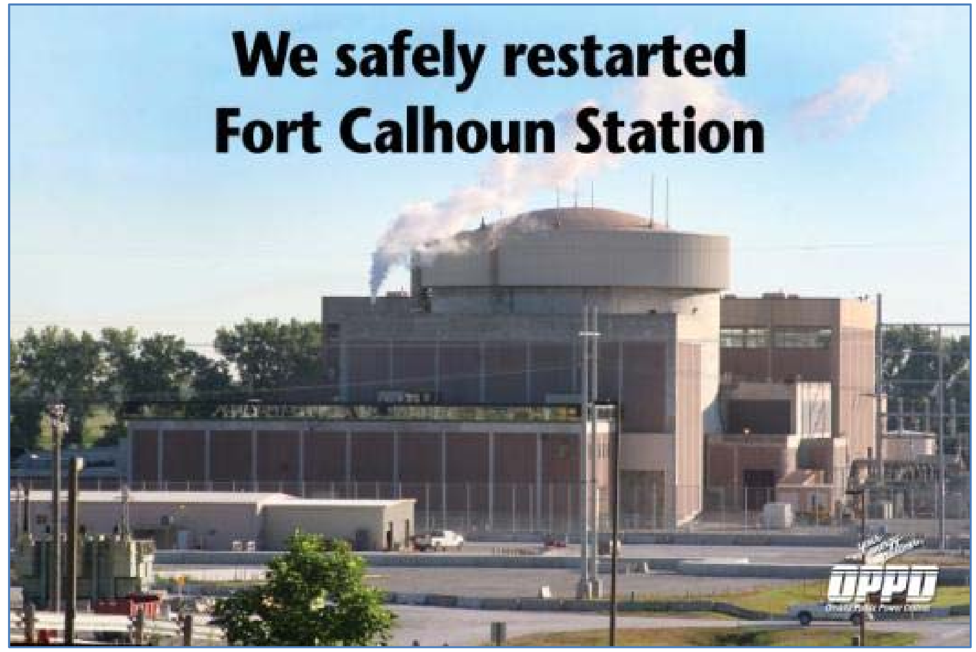
What it Took

- 8,000,000 person-hours
- 69,000 task completions
- 20-year operating agreement with Exelon
- More than 450 restart checklist items closed
- Industry-leading measurement of safety culture



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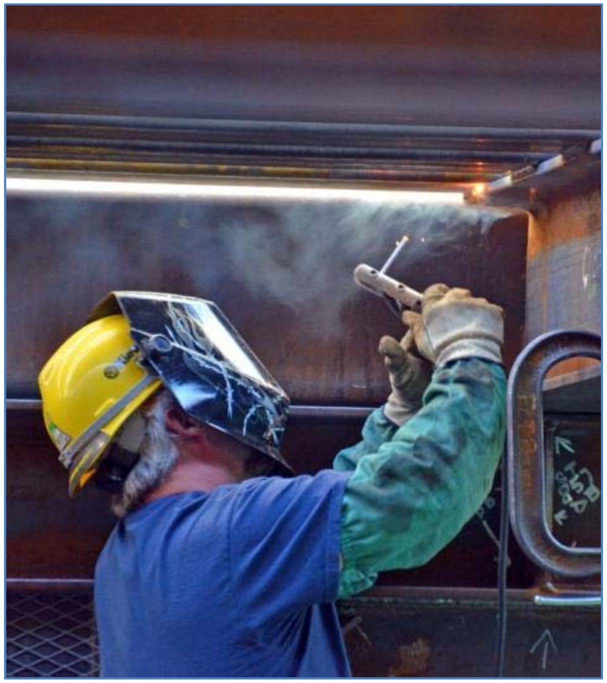
What it Took – The Details

- Work orders planned: 26,956
- Work order tasks completed: 50,197
- Engineering changes completed: 187
- NRC inquiries addressed: 1,885
- Modifications installed: 90
- Modification tasks: 11,614
- Parts issued: 50,317
- Radiography exams (RT shots): 474
- Clearances used: 7,906
- Clearance tags hung and removed: 34,547
- Dose to complete the work:180.113 REM



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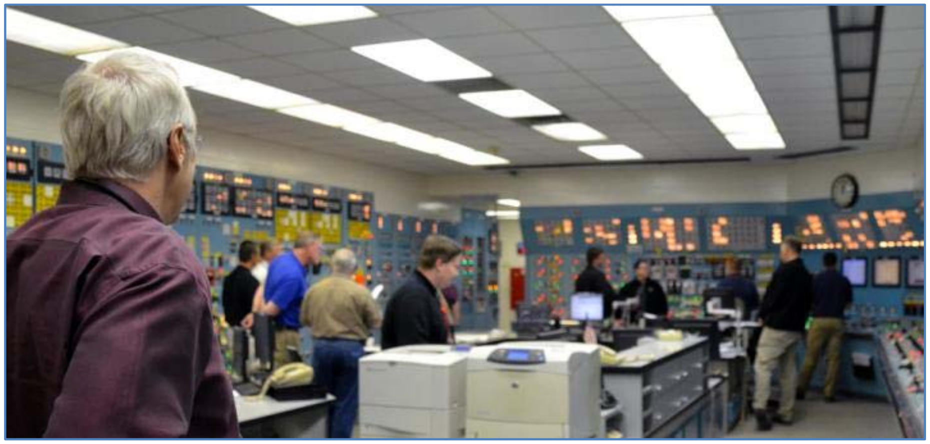
What it Took – The Details

- CAP items assigned: 51,726
- Root Cause Analyses (RCA's) assigned: 77
- Apparent Cause Analyses (ACA's) assigned: 287
- Simple Causes assigned: 16,742
- D-level Condition Reports (CRs) assigned: 34,384



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Supporting Actions

- Fukushima Response Project
- Beyond Design Basis Flood Mitigation
- Tornado-Borne Missile Protection
- Containment Penetrations & Internal Structures
- Security Upgrades

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Fukushima Response Project

- Project scope
  - Flooding reevaluation and seismic evaluation
  - Flooding and seismic walk-downs
    - Results submitted to the NRC
    - Actions ongoing
  - Mitigating strategies for beyond design basis external events
  - Strategy developed and submitted to NRC
    - Portable equipment pre-staged at FCS
    - Procedures (Admin/Operations/PM/Testing)
    - Staffing
    - Communications (internal and external)
  - Spent Fuel Pool Instrumentation (SFPI)
    - SFPI modifications submitted to the NRC

Portable Submersible Pumps

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Beyond Design Basis Flood Mitigation

- New portable system
- Mitigates effects of floods above 1,014' msl elevation
- Designed and tested for BDB conditions

Portable Skids for Water and Power Distribution

Portable Diesel Generators

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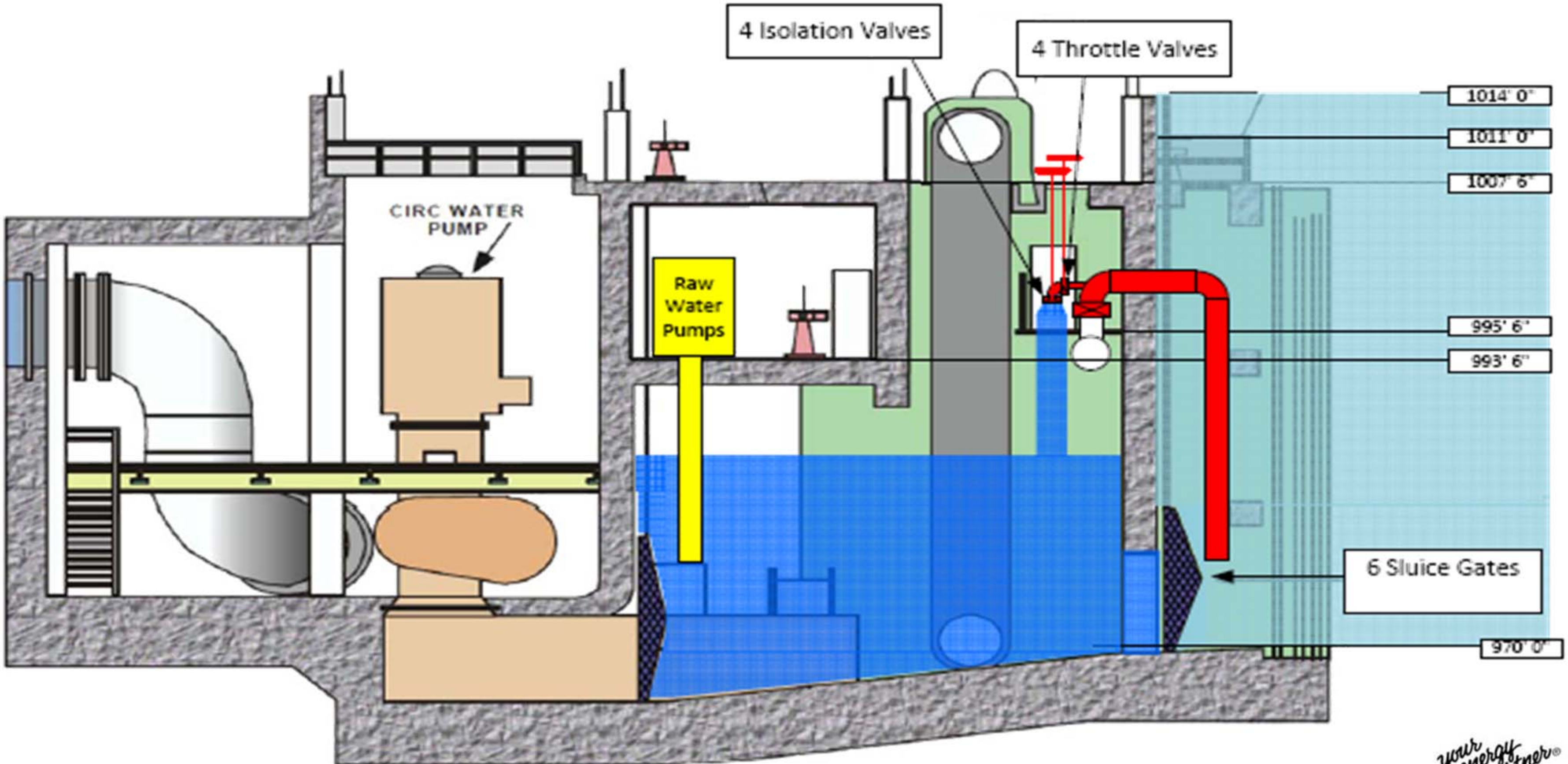
Design Basis Flood Mitigation

- Developed new flood mitigation system
  - Completed reactor analysis to support system design
  - Procured equipment and constructed and tested portable system
    - » Electrical generator with fuel supply
    - » Appropriate pumping systems
    - » Necessary piping, hoses and connections/fittings

  - Revised abnormal operating procedures – procedures validated on simulator and during field walk downs
  - Established equipment storage location
  - Finalizing emergency preparedness and security procedures
  - Developing preventative maintenance and testing procedures

Design Basis Flood Mitigation

Improved Intake Level Control Strategy



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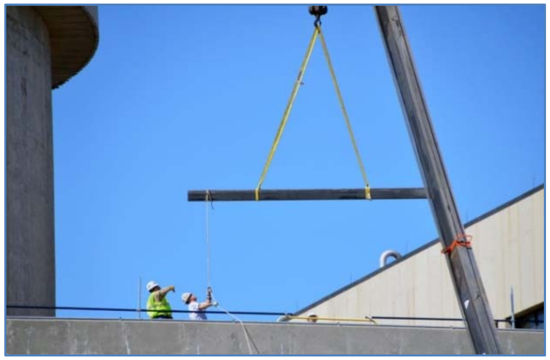
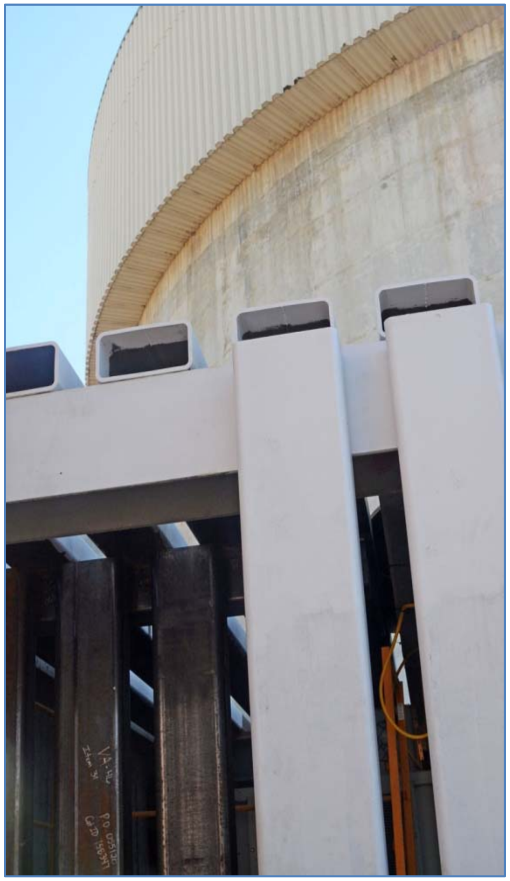
Tornado-Borne Missile Protection

- Protection of key equipment from potential tornado-borne missiles
- Used 250 tons of steel
- Completed 37 modifications





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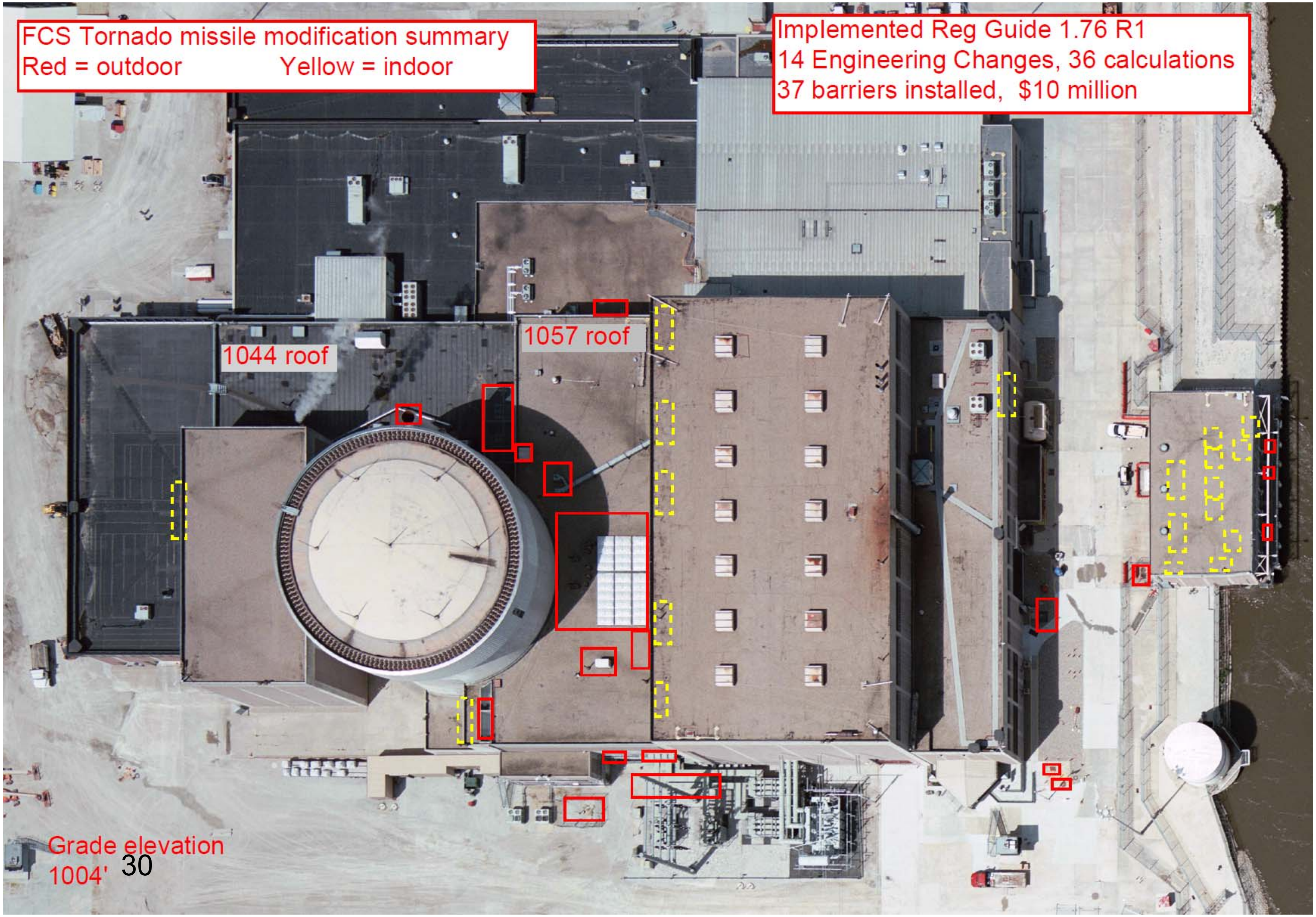
Tornado-Borne Missile Protection



Containment Penetration Replacement

Replaced 363 containment penetrations susceptible to radiation damage

CONTAINMENT PENETRATION CHART

	1	2	3	4	5	6	7	8	9	10	11
F	F1 12 Feedthroughs Replaced 7 Plugs Installed	F2	F3	F4 4 Plug Installed	F5 2 COAX Feedthroughs Replaced 7 Plugs Installed	F6 4 Feedthroughs Replaced 7 Plugs Installed	F7 26 Feedthroughs Replaced 1 Plug Installed	F8 26 Feedthroughs Replaced 1 Plug Installed	F9 26 Feedthroughs Replaced 1 Plug Installed	F10 4 Feedthroughs Replaced 2 Plugs Installed	F11 9 Plugs Installed
E	E1 2 Plugs Installed	E2 1 Feedthroughs Replaced	E3	E4 25 Feedthroughs Replaced 2 Plugs Installed	E5	E6 3 Plugs Installed	E7	E8 12 Feedthroughs Replaced 5 Plugs Installed	E9 1 Plug Installed	E10 21 Feedthroughs Replaced 6 Plugs Installed	E11
D	D1 16 Feedthroughs Replaced 4 Plugs Installed	D2 13 Feedthroughs Replaced 5 Plugs Installed	D3	D4 2 Feedthroughs Replaced 17 Plugs Installed	D5 4 Feedthroughs Replaced 4 Plugs Installed	D6 5 Feedthroughs Replaced 2 Plugs Installed	D7 7 Plugs Installed	D8	D9	D10 3 Feedthroughs Replaced 5 Plugs Installed	D11
C	C1 17 Feedthroughs Replaced 6 Plugs Installed	C2	C3	C4 18 Feedthroughs Replaced	C5 7 Plugs Installed	C6 3 Plugs Installed	C7 3 Feedthroughs Replaced 3 Plugs Installed	C8 13 Feedthroughs Replaced 8 Plugs Installed	C9	C10 5 Plugs Installed	C11 19 Feedthroughs Replaced
B	B1 2 Plugs Installed	B2 1 Feedthroughs Replaced 1 Plug Installed	B3	B4 2 COAX Feedthroughs Replaced 4 Plugs Installed	B5 16 Feedthroughs Replaced 1 Plug Installed	B6	B7	B8	B9	B10 18 Feedthroughs Replaced 1 Plug Installed	B11 4 Plugs Installed
A	A1 22 Feedthroughs Replaced 2 Plugs Installed	A2 13 Feedthroughs Replaced 4 Plugs Installed	A3	A4 1 Feedthroughs Replaced 4 Plugs Installed	A5	A6	A7	A8	A9	A10	A11 3 Feedthroughs Replaced 6 Plugs Installed
	PAL Door 4 Feedthroughs Replaced 4 Plugs Installed	Sub-Hull 6 Feedthroughs Replaced 2 Plugs Installed									

KEY

Indicates modifications were performed on this CEP Canister

Indicates NO modifications were performed on this CEP Canister

Summary

EC 58713
EC 56397

Replaced 344 Feedthrough assemblies. Replaced 14 Feedthrough assemblies.

EC 56947
EC 57582

Removed and plugged 10 existing spare Feedthroughs.
Removed and plugged 172 existing spare Feedthroughs.

40 of 66 Penetrations Part of Scope

2 Personnel Access Doors Part of Scope

2 ECCS Containment Sump Valve Penetrations Part of Scope

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Containment Internal Structures

- OPPD committed to:
  - Evaluate the structural design margin for the containment internal structure, and reactor cavity and compartments, and resolve any deficiencies in accordance with FCS's CAP
  - Regarding Beams 22A and Beam 22B under Safety Injection Tanks 6B/D, resolve any deficiencies in accordance with the CAP
- Significant effort and resources utilized to analyze the containment internal structure and develop resolution strategies.
- Resolution Strategy
  - Reactor Vessel Head stand
    - Replace current existing pedestal supports with deep beams that span the floor to take the load to adjacent walls and columns

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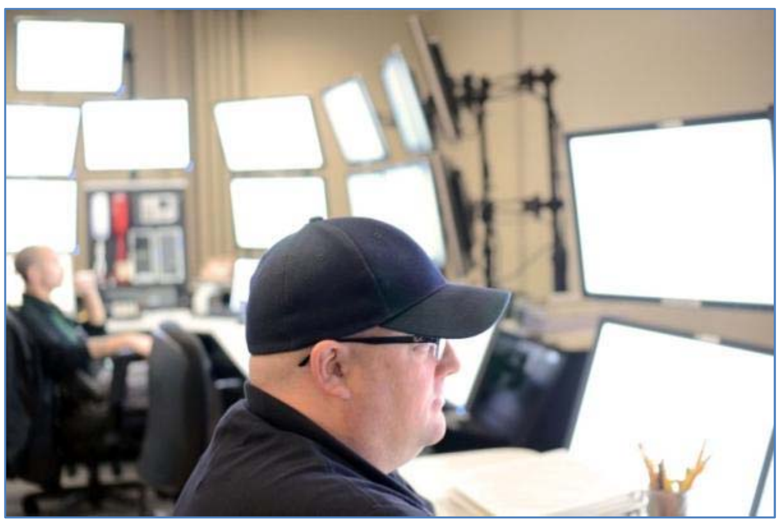
Security Upgrades

- Physical security upgrades
  - Enhanced security barriers
  - Central Alarm Station (CAS)
  - Secondary Alarm Station (SAS)
  - Force-on-Force exercises



Recent Events

- 2014 High-Water Event
- Problem Identification & Resolution Inspections
- Design and Licensing Basis Control and Use

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2014 High-Water Event

- Heavy June rainfall upstream on the Missouri River
- NWS projected a crest of 1,004-1,006 feet
- Conservative bias – prepared for plant shutdown

2014 High-Water Event

- Reduced reactor power to 30 percent
- Filled and staged sandbags, installed AquaBerms and Hesco barriers
- River crested at 1,001 feet on Saturday, June 21
- Stood down flood-mitigation teams and commenced power ascension

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Problem Identification & Resolution

- One extended NRC inspection in July 2014
- FCS performance didn't meet expectations
  - Many improvements made in the Corrective Action Program
    - Training and qualification of workers
    - More detailed metrics and performance indicators
    - Improved ownership and accountability behaviors in most functional areas
  - Results show continued improvement is needed
    - More rigorous evaluation to determine causes of issues
    - Improved timeliness of corrective actions
    - Ensure actions taken completely address the issue to prevent recurrence
    - Better tracking of actions associated with regulatory commitments
    - Comprehensive self assessments to identify lower level items

Design and Licensing Basis Control and Use

- OPPD's post-restart commitment states that:
  - After restart, OPPD will complete a significant effort to perform a risk-focused reconstitution of the:
    - Design basis,
    - Licensing basis, and
    - Updated Safety Analysis Report
- As part of this project, OPPD will:
    - Ensure proper classification of equipment,
    - Convert to a safety-related "Q List" approach for equipment classification, and
    - Complete a key calculation review
  - A pilot program will be completed during 2014 on a selected system to "check and adjust" the process, scheduling and resource allocation
  - Complete the reconstitution project before the end of 4th quarter 2018

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Closing Remarks

- NRC Special Oversight Timeline
  - 2011 Missouri River Flood
  - Electrical Bus Fire
  - Flood Recovery Confirmatory Action Letter (CAL)
  - Manual Chapter 0350 and Restart CAL
  - Operating Services Agreement with Exelon
  - CAL Closure and Restart
- Supporting Actions
  - Beyond Design Basis Flood Mitigation
  - Fukushima Response Project
  - Tornado-borne Missile Protection
  - Containment Penetrations & Internal Structures
  - Security Upgrades
- Recent Events
  - 2014 High Water Event
  - Problem Identification & Resolution Inspections
  - Design and Licensing Basis Control and Use
- Closing Remarks

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Implementation of IMC 0350 Process at Fort Calhoun Station

Tony Vegel - 0350 Panel Chair/RIV

Mike Hay - Branch Chief, DRP, RIV

NRC Actions

- **Yellow Flooding Finding – October 2010**
- **Site Flooding – May through September 2011**
- **Confirmatory Action Letter (CAL) – September 2011**
  - **Focused on flood recovery actions**
- **Security Greater-than-Green Findings – January & September 2011**

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NRC Actions

- **Reactor Protection System White Finding – July 2011**
- **Licensee moved to Column IV – September 2011**
- **Issued Red Finding (Switchgear Fire) – December 2011**
- **Fort Calhoun Transitions to IMC 0350 Process – December 2011**

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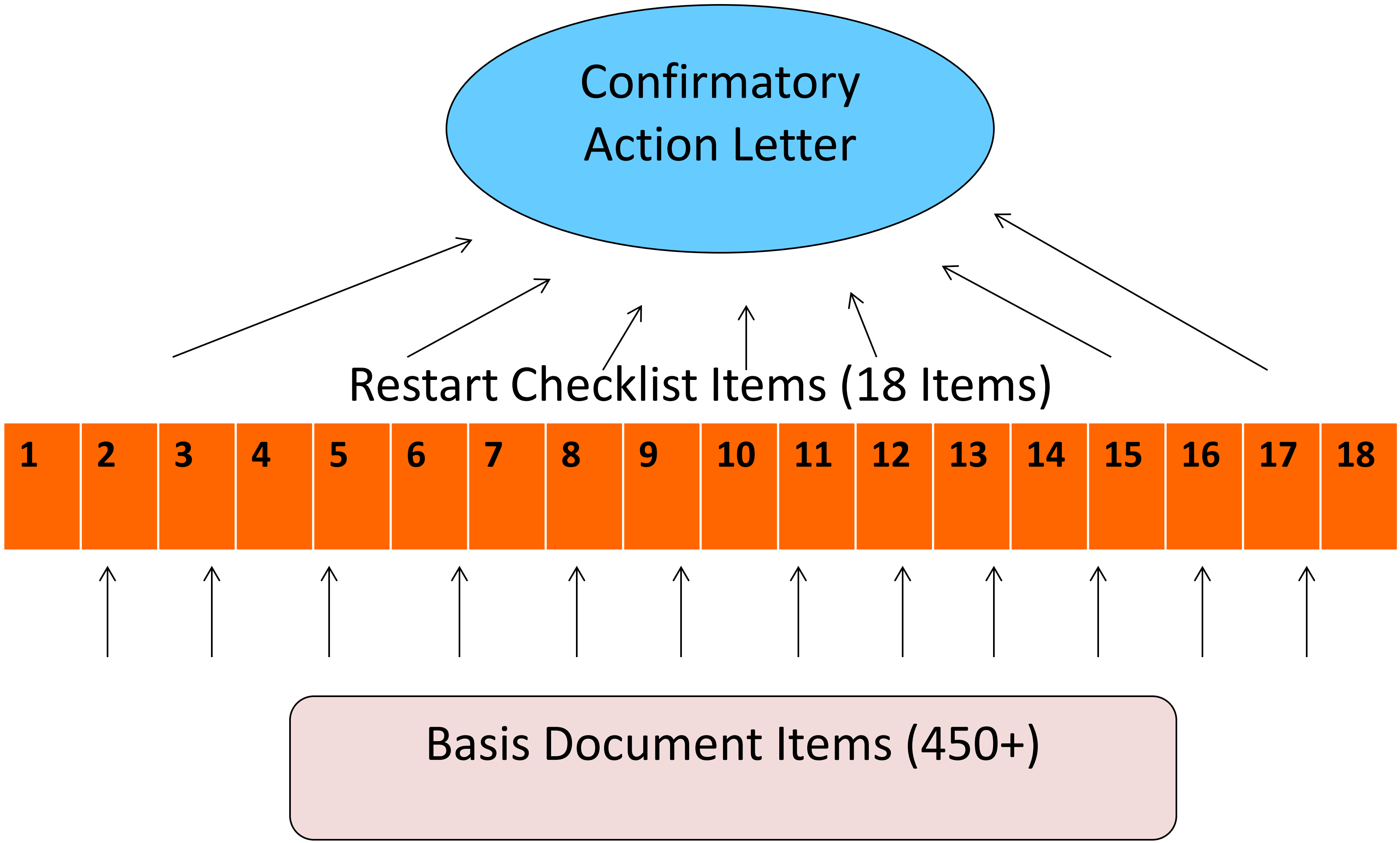
NRC Actions

- **Issued Revised CAL – June 2012**
  - **Flood recovery actions**
  - **Performance problems**

- **Issued CAL basis document – November 2012**
  - **Living document**
  - **Provides inspection strategy and inspection status**


Confirmatory Action Letter
Restart Checklist Items (18 Items)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
Basis Document Items (450+)

NRC Actions

- **Issued revised CAL – February 2013**
  - **Added three items to restart checklist**
  - **White Safety System Functional Failure Performance Indicator, containment internal structures, and containment electrical penetrations**

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NRC Actions

- **Regional Coordination of Inspection Activities**
  - **Multiple team inspections**
  - **Resident Inspector inspections**
  - **Inspectors from all four regions and headquarters**
- **Approximately 100 NRC staff involved**

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NRC Actions

- **Headquarters Activities**
  - **Licensing Actions**
    - **Tornado Missile License Amendment Request (LAR)**
    - **High Energy Line Break LAR**
  - **Task Interface Agreements (TIA's)**
    - **Containment internal structure**
    - **Tornado Missile 50.59 and operability evaluations**

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Restart Readiness Decision

- **Restart Checklist inspection activities completed (Dec. 2013)**
- **Comprehensive corrective actions independently verified**
- **Verified plant, people, and processes adequate to support plant restart**
- **Approximately 23,000 hours of NRC inspection, assessment, and licensing activities conducted in 2013**
- **CAL closed (Dec. 2013)**

Post-Restart

- **NRC issued Post-Restart Confirmatory Action Letter December 17, 2013**
  - **Key areas for sustained performance improvement**
    - **Human Performance**
    - **Safety Culture**
    - **Corrective Action Process**
    - **Design Basis Reconstitution**

Current Oversight Status

- Routine inspections
  - Resident Inspectors
  - Regional inspections
- Team inspection conducted July 2014
  - Assessed Corrective Action Process effectiveness
  - Assessed Post-Restart Confirmatory Action Letter items

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Current Assessment Results

- **Licensee effectively implementing improvement initiatives in the following key areas:**
  - **Organizational Effectiveness, Safety Culture, Safety Conscious Work Environment**
  - **Site Operational Focus**
  - **Procedures**
  - **Nuclear Oversight**
  - **Transition to the Exelon Nuclear Management Model**

Approximately 130 of 180 Confirmatory Action Letter items closed

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Current Assessment Results

- **Inconsistent effective implementation of corrective action program**
- **Examples include:**
  - **Evaluations of degraded and non-conforming conditions**
  - **Resolution of previously issued NRC findings**

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Current Status and Path Forward

- **Public meetings to provide for open and transparent oversight process**

- **Performance assessment for transition to normal level of regulatory oversight**

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Criteria for Transitioning FCS to Normal NRC Oversight Process

- **An effective long-range improvement program**
- **Sufficiently implementing the corrective action program**
- **Demonstrated safe plant operation and overall improving performance**
- **Controls in place to address the plant-specific issues that resulted in increased oversight**

Summary

- **IMC 0350 Process is an effective tool for providing increased level of oversight to plants with performance issues**

ACRONYM LIST

- **IMC - Inspection Manual Chapter**
- **CAL - Confirmatory Action Letter**
- **LAR - License Amendment Request**
- **TIA - Task Interface Agreement**