UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

October 11, 2007

MEMORANDUM TO: O. Maynard, Chairman, Plant Operations Subcommittee

FROM: Maitri Banerjee, Senior Staff Engineer, ACRS **\RA**

SUBJECT: THE MINUTES OF THE MEETING OF THE SUBCOMMITTEE ON PLANT OPERATIONS WITH NRC REGION IV ON AUGUST 14, 2007, IN ARLINGTON, TEXAS

The minutes for the subject meeting is attached. It incorporates comments from your review. If you are satisfied with these minutes please sign, date, and return the attached certification letter.

Attachments: Certification Letter
Minutes

cc w Attachments: Plant Operations Subcommittee Members

cc w/o Attachments: F. Gillespie
C. Santos
S. Duraiswami
C. Brown

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

MEMORANDUM TO: Maitri Banerjee, Senior Staff Engineer, ACRS

FROM: O. Maynard, Chairman, Plant License Renewal Subcommittee

SUBJECT: CERTIFICATION OF THE MINUTES OF THE MEETING OF THE SUBCOMMITTEE ON PLANT OPERATIONS WITH NRC REGION IV ON AUGUST 14, 2007, IN ARLINGTON, TEXAS

I hereby certify, to the best of my knowledge and belief, that the minutes of the subject meeting on August 14, 2007, are an accurate record of the proceedings for that meeting.

Otto L. Maynard

10/13/07
O. Maynard, Date
Plant License Renewal Subcommittee Chairman

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MINUTES OF THE MEETING OF THE SUBCOMMITTEE ON PLANT OPERATIONS
VISIT TO NRC REGION IV ON AUGUST 14, 2007
ARLINGTON, TEXAS

On August 14, 2007, the ACRS Subcommittee on Plant Operations held a meeting at the NRC Region IV (RIV) office in Arlington, Texas. The purpose of the meeting was to discuss the regional inspection and operational activities. The meeting was open to the public. In addition to the ACRS and NRC staff from RIV, representatives from Southern California Edison Company and Stars, Regulatory Affairs attended the meeting. The meeting was convened at 8:30 a.m. and adjourned around 4:10 p.m. No written comments or requests to make oral statements were received from the public related to this meeting.

Attendees

ACRS Members/Staff	**RIV Presenters**	**RIV Staff**	**NRR Staff**
Otto Maynard (Chairman)	Linda Smith	Brian Tindell	Paul Bonnett
Graham Wallis (Member)	Tony Gody	Mark Haire	
William Shack (Member)	Joseph Lopez	Don Stearns	
George Apostolakis (Member)	Michael Hay	Larry Ricketson	**Public**
Michael Corradini (Member)	John Hanna	Robert Latta	Michael McBearty (SCE)
Said Abdel-Khalik (Member)	Linda Howell	Carl Corbin	Carl Corbin (STARS)
Mario Bonaca (Member)	Blair Spitzberg	Mike Chambers	
Maitri Banerjee (DFO)	Greg Warnick	Brian Larson	**Other ACRS Staff**
	Wayne Walker	Hasan Abuseini	David Bessett
RIV Presenters	David Loveless	Teresa Ryan	Girija Shukla
Bruce Mallett	George Replogle	Joseph Bashore	Jamila Perry
Pat Gwynn	Kelly Clayton	Claude Johnson	
Dwight Chamberlain	Paul Elkmann	Tom Stetka	
Roy Caniano	James Drake		

The presentation slides and handouts used during the meeting are attached to the Office Copy of these minutes. The presentations to the Subcommittee are summarized below.

Chairman Maynard convened the meeting by introducing the ACRS members present. Mr. Maynard stated that the purpose of the meeting was to discuss regional inspection and operational activities and gain insights.

Mr. Pat Gwynn, the Deputy Regional Administrator of RIV, introduced the staff and presented an overview of the RIV activities. He described the special challenges that face Region IV. Dr. Bruce Mallett, the Regional Administrator, noted that the large area of geographic coverage provides a special challenge to RIV. Other important issues facing RIV include: recruitment and retention of staff; maintenance of the resident inspector pool; knowledge management and remembering lessons learned; consistency in defining cross-cutting issues/aspects; best practices and alignment in the inspection finding significance determination process (SDP); external communication and outreach; and the level of verification in the inspection program.

Mr Roy Caniano, Deputy Director, Division of Reactor Safety, and Mr. Joe Lopez, Human Resource Management, presented an overview of the RIV activities related to knowledge management (KM). Mr. Caniano discussed the communication and implementation of the KM activities, strategies, and staff development. Although, every region's plan and activities in this area are prepared to meet their unique needs, the regions communicate through a steering committee at the NRC Head Quarters. RIV is investigating ways to share their experience in this area with the industry.

RIV staff presented three case studies and best practices in the area of the reactor oversight process (ROP). The first case study looked at a long and involved refueling outage during which major components, including the steam generators, reactor vessel head, pressurizer, main transformer and the containment sump screen were replaced. Region IV inspectors identified problems in many areas that the licensee had performed well historically.

The second case study involved a plant where a confirmatory action letter (CAL) process was completed through a successful implementation of the ROP to ensure licensee's corrective actions were effective. The third case study was with a plant where after ten years of good performance several events, allegations and inspections identified performance degradation. The RIV staff stated that the ROP provided better tools, a structured and systematic assessment process with appropriate focus to address the performance degradation, and sharing of information between the inspectors and management. The RIV inspectors also discussed the inspection best practices. The ACRS members asked many probing questions regarding the details of the region's experience in these case studies.

The RIV staff also presented their experience with recent technical challenges in the area of reactor decommissioning and independent spent fuel storage installation. The issues included a licensee's inability to find a transportation route for disposal of the old reactor pressure vessel head (Class C low level waste), missing material, and the cask handling crane issues.

In their presentation on the safety culture initiative, the RIV staff stated that in addition to evaluating for significance, an inspection finding of more than minor significance related to current performance would be evaluated to determine if it has a cross-cutting aspect. The three cross-cutting areas in ROP comprise of human performance, problem identification and resolution, and the safety conscious work environment. Each of these areas cover multiple safety culture components. Three or more inspection findings, binned under the same cross-cutting aspect, may indicate a substantive cross-cutting issue at a plant. Significant inspection findings against individual licensed operators will be reviewed under the traditional enforcement policy as a violation of the operators' license which will not await the completion of the assessment process described above. RIV initiated a cross-cutting task group effort, expected to be complete by the end of the year, to identify the differences and similarities between the regions and seek input from the utilities regarding implementation of the cross-cutting aspects.

RIV staff shared their experience with the component design basis team inspections, its successes and challenges. RIV believes that these inspections were very effective for a deeper understanding of the deign issues that may not have been identified and corrected otherwise.

In a round table discussion, RIV staff discussed how inspection findings are reviewed thru the significance determination process (SDP) in the ROP. The event itself is not evaluated for risk significance thru the SDP to determine the action matrix response, but the event initiator (e.g., reactor scram, loss of feedwater, loss of power) is evaluated for risk. The risk number is then factored into the region's decision making process to determine if a reactive or special inspection should be undertaken to better understand any performance deficiencies. The identified performance deficiencies are processed thru the SDP and evaluated for cross-cutting issues. The RIV staff shared their experience on areas of potential improvement, level of detail in risk modeling, and communicating lessons learned among the inspectors and with the industry.

The ACRS members visited the RIV incident response center, with the RIV staff.

In his closing statement, Dr Mallett pointed out that RIV revisits its programs each year and builds into the ROP process implementation. Another key element, he pointed out, was maintaining the expertise and diligence of the staff.

The ACRS Chairman and the members provided their appreciation and feedback on the region's outstanding presentations. Chairman Maynard adjourned the meeting by thanking everyone attending the meeting.

ADAMS DOCUMENT PROFILE

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RN0109

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
REGION IV VISIT
August 14, 2007

-AGENDA-

Time	Topic	Presenter	Time Allotted
8:30 - 9:00 am	Region IV Overview and Challenges	Dr. Mallett P. Gwynn	30 minutes
9:00 - 9:30	Knowledge Management	J. Lopez R. Caniano	30 minutes
9:30 - 9:50	Reactor Oversight Process (ROP) Case Study #1	J. Hanna	20 minutes
9:50 - 10:10	ROP Best Practices	M. Hay	20 minutes
10:10 - 10:20	BREAK	-	10 minutes
10:20 - 10:40	ROP Case Study #2	W. Walker	20 minutes
10:40 - 11:10	ROP Case Study #3	G. Warnick	30 minutes
11:10 - 12:10	LUNCH	-	1 hour
12:10 - 12:40 pm	Incident Response Center Tour	L. Howell	30 minutes
12:40 - 1:05	Independent Spent Fuel Storage Installations and Decommissioning	Dr. Spitzberg	25 minutes
1:05 - 1:35	Safety Culture	L. Smith D. Chamberlain R. Caniano	30 minutes
1:35 - 2:05	Component Design Basis Inspections	G. Replogle	30 minutes
2:05 - 2:20	BREAK	-	15 minutes
2:20 - 3:30	ROP Roundtable Discussion ACRS Questions and Answers	T. Gody K. Clayton P. Elkmann G. Warnick G. Replogle D. Loveless J. Drake	1 hour 10 minutes
3:30 - 3:50	Closing Remarks	Dr. Mallett P. Gwynn	20 minutes

RIV CONTACT: Brian Tindell, bwt@nrc.gov or (817) 860-8244
ACRS CONTACT: Michael Junge, mxj2@nrc.gov or (301) 415-6855

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

August 7, 2007

RN 0109 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS) VISIT TO REGION IV

EFFECTIVE: Immediately

DATE CANCELED: 08/17/07

CONTACT: Brian Tindell x244

DISTRIBUTION: Standard

APPROVAL: /RA/
Bruce S. Mallett, Regional Administrator

A. Purpose/Discussion

To announce the upcoming ACRS Operations Sub-Committee visit to the Region IV office. During this public meeting, the regional staff will be presenting information to the ACRS regarding the regional office's operations.

B. Action

The meeting agenda is attached. All staff are welcome to attend the presentations.

Enclosure: ACRS Visit to Region IV Agenda

cc w/Enclosure:
RIV Coordinator, OEDO **(MAK3)**

SUNSI Review Completed: BWT ADAMS: ☐ Yes ■ No Initials: BWT
☐ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive
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RIV:DRS/OB	C:DRS/OB	D:DRS	D:DRP	D:DNMS
BWTindell	ATGody	RJCaniano	ATHowell	LDWert
/RA/	**/RA/**	**/RA/**	**/RA AVegel for/**	**/RA/**
7/27/07	7/31/07	8/1/07	8/1/07	8/1/07

D:DRMA	DRA	RA		
MLHays	TPGwynn	BSMallett		
/RA/	**/RA/**	**/RA/**		
8/2/07	8/7/07	8/7/07		

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INTRODUCTORY STATEMENT BY THE CHAIRMAN OF THE
MEETING OF THE ACRS SUBCOMMITTEE
ON PLANT OPERATIONS
ARLINGTON, TEXAS

August14, 2007

Mr. Maynard

The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards Subcommittee on Plant Operations. I am Mario Bonaca, Chairman of the Subcommittee.

Other members in attendance are Graham Wallis, Bill Shack, Said Abdel-Khalik, George Apostolakis, Michael Corradini, and Mario Bonaca.

The purpose of the meeting today is to discuss regional inspection, and operational activities. The Subcommittee will hold discussions with representatives of the NRC staff regarding these matters. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full Committee. Maitri Banerjee is the Designated Federal Official for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal Register* on July 20, 2007.

A transcript of the meeting is being kept and will be made available as stated in the Federal Register Notice. It is requested that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

(Chairman's comments here)

Our first speaker of the day will be Dr. Mallett.

October 10, 2007

Memo To: File

From: Maitri Banerjee, Sr. Staff Engineer
ACRS **\RA**

Subject: ACRS OPERATIONS SUBCOMMITTEE MEETING AT NRC REGION IV ATLANTA, GA ON AUGUST 14, 2007- COI REVIEW

This is to document the conflict of interest (COI) review I performed prior to the meeting for the following ACRS members attending the meeting:

Otto Maynard - Chairman
George Apostolakis - Member
Michael Corradini - Member
Mario Bonaca - Member
Bill Shack - Member
Graham Wallis - Member
Said Abdel-Khalik - Member

The purpose of the ACRS meeting was to gather information on the reactor oversight program implementation and related activities at Region IV. I have reviewed the COI information available on the ACRS ACT database and found no conflict.

cc:
C. Santos
M. Afshar-Tous

mB

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards Plant Operations Subcomittee

Docket Number: (not applicable)

Location: Arlington, Texas

Date: Tuesday, August 14, 2007

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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

August 14, 2007

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on August 14, 2007, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

SUB-COMMITTEE FOR PLANT OPERATIONS

REGION IV VISIT

Tuesday, August 14, 2007

Training Conference Room, Fourth Floor

US NRC Region IV

611 Ryan Plaza Drive

Arlington, Texas

The above-entitled meeting was conducted at 8:30 a.m., OTTO MAYNARD, ACRS Operations Sub-Committee Chairman, presiding.

ATTENDEES:

ACRS Members

Dr. William Shack, Chairman

Dr. Mario Bonaca, Vice Chairman

Dr. Said Abdel-Kahlik, Member-at-Large

Dr. George Apostolakis, Member

Dr. Michael Corradini, Member

ATTENDEES (Continued):

Dr. Graham Wallis, Member

ACRS Staff

Maitri Banerjee

David Bessette

Jamila Perry

Girija Shukla

Region IV Staff

Bruce Mallett, Regional Administrator

T. Pat Gwynn, Deputy Regional Administrator

Dwight Chamberlain, Director, Division of Reactor Safety

Roy Caniano, Deputy Director, Division of Reactor Safety

Tony Gody, Chief, Operations Branch

Michael Hay, Chief, Projects Branch C

Linda Howell, Chief, Response Coordination Branch

Linda J. Smith, Chief, Engineering Branch 2

Dr. D. Blair Spitzberg, Chief, Field Cycle & Decommissioning Branch

David P. Loveless, Senior Reactor Analyst

John D. Hanna, Senior Project Engineer

George Replogle, Senior Project Engineer

Kelly Clayton, Senior Operations Engineer

Wayne Walker, Senior Project Engineer

Greg Warnick, Senior Resident Inspector

Joseph L. Lopez, Human Resources Management Specialist

James F. Drake, Operations Engineer

Paul J. Elkmann, Emergency Preparedness Analyst

Robert Latta, Coordinator for New Reactors

Larry Ricketson, Health Physics Inspector

Don Stearns, Health Physics Inspector

Mark Haire, Senior Operations Engineer

Tom Stetka, Senior Operations Engineer

Claude E. Johnson, Chief, Branch A

Joseph Bashore, Project Engineer, Division of Reactor Projects

Gwen Ryan, summer engineering associate

Hasan Abuseini, reactor inspector, Engineering Branch 2

Mike Chambers, Project Engineer, Division of Reactor Projects

Brian Larson, Operations Engineer, Division of Reactor Safety

Brian Tindell, Operations Engineer, Division of Reactor Safety

Greg Werner, Senior Project Engineer, Division of Reactor Projects

<u>Office of NRR Staff</u>

F. Paul Bonnett, Senior Reactor Analyst

Members of the Public

Carl Corbin, STARS Regulatory Affairs, Luminant Power, Comanche Peak

Fred Madden, Director, Oversight and Regulatory Affairs, Luminant Power, Comanche Peak

Michael McBrearty, Nuclear Regulatory Affairs Division, San Onofre Nuclear Generating Station (SONGS)

I N D E X

P R O C E E D I N G S

MR. MAYNARD: Good morning. Let's go ahead and get the meeting going. I'd like to call the meeting to order.

This is a meeting of the Advisory Committee on Reactor Safeguards. This is the Committee for Plant Operations. My name is Otto Maynard, and I'll be the chairman for the sub-committee today. ACRS members in attendance are Graham Wallis, George Apostolakis, Bill Shack, Mario Bonaca, Michael Corradini and Said Abdel-Kahlik.

Now, before I get any further into this, I'd like to go ahead and turn it over to Tony Gody for just a moment here to give some administrative remarks.

So, Tony?

MR. GODY: Thank you.

Okay. Welcome to Region IV. Today is going to be a very interesting day. We're going to have very good dialogue. I encourage lots of questions. You'll hear a number of presentations, on many different topics. We will attempt to address all the questions that you provided us originally through a series of topical discussions.

Before we start, I'd like to point out some administrative things. This is a public meeting, and the meeting is between the ACRS and Region IV. And should Mr. Maynard wish to open the floor up for public comments, he'll do that at some point later in the meeting.

Administratively, there's restrooms out in the elevator lobby. You can exit either door and go into the elevator lobby, and there's a men's and women's room. There is security here. So if you do not have a badge, just indicate that you're here for the ACRS meeting, and the security officer will let you in.

In the unfortunate event of a fire or a fire alarm, there are exits here and here. You go out into the elevator lobby. There are two doors, on either end of the elevators. Please go downstairs and exit the building to the west, and that is in that direction. And you want to actually head southwest to the parking lot and look for me. And I will take attendance and make sure that everybody is safe.

If there's any other administrative needs, just contact me. I'm your host. We do have public meeting comment forms on the table over here. I would encourage each and every one of you to provide comments on our public meetings. Region IV constantly strives to improve our public meetings, and we use that feedback and take it very seriously to improve our public meetings.

And I guess before I start, would you have any other comments you'd like to make before I turn it over to Pat Gwynn, sir?

MR. MAYNARD: Yes. I've got a few more comments to get out of the way here.

Each year, the ACRS Plant Operations Sub-Committee tries to visit one of the power plants and also spend time with the corresponding region for that plant. It gives us better insights on what's actually going on with a number of the issues that we deal with back at headquarters; it gives us an opportunity to get insights on the actual impacts, the actual advantages, disadvantages and things to help us in our deliberations when we do meet on issues back in Washington.

The purpose of today's meeting is to discuss regional inspection and operational activities. We'll hold discussions with the regional staff, encourage and get two-way dialogue between ACRS and the regional staff. This helps us gather information.

There are no specific issues before the ACRS right now that this meeting is addressing; however, the regional insights and information that we get from these meetings are very valuable in deliberating things that are coming up in the future and a number of the issues that we will be dealing with over the next year or so. So these meetings we find very valuable to us.

The designated federal official for today's meeting is Maitri Banerjee. And I would like to say that the rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on July 20, 2007. I will try to make some time available if there are any public comments at the end, but this is a meeting between the ACRS staff and the Region IV staff, and so that's where the discussions are going to be held primarily.

A transcript of the meeting is being kept and will be made available, as stated in the Federal Register notice. It's requested that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

Before I turn the meeting over to Dr. Mallett, I'd like to say that this is kind of a unique meeting for me. It's a different -- I've been to a number of meetings in Region IV. This is the first time that I've been as an NRC employee; most of the time, I've been defending something that happened at my power plant and have been on the tail-end of an enforcement conference or something. So this, I think, will be a little better for me.

My colleagues very aptly remind me every once in awhile if I start getting defensive that I'm not the one being challenged here. So we'll try to keep that straight.

Region IV has several unique aspects to it, challenges and responsibilities. I'd like to now turn it over to Dr. Mallett to discuss some of those and to start leading off the staff presentations.

So, Dr. Mallett?

DR. MALLETT: Actually, Pat Gwynn's going to lead us on this.

MR. GWYNN: And good morning, Mr. Maynard, Dr. Shack and members of the Advisory Committee on Reactor Safeguards. We welcome you to Region IV, the friendly region. And we value the opportunity to inform you about our region and the work that we do.

I wanted to first, if you don't mind, take just a minute to introduce the members of the NRC staff that we have present with us here today. And we've asked all of our presenters to come to this opening session so that you'll have a chance to see them and to hear their names before they actually have to speak.

Of course, you've met Dr. Mallett, I believe, our regional administrator. And I'll ask each of the NRC staff members to stand up and just mention their names at this point in time.

MR. MAYNARD: And they're going to need to come to a microphone or pass a microphone around.

MR. GWYNN: Let's do that.

MR. CHAMBERLAIN: Good morning. I'm Dwight Chamberlain; I'm the Director of the Division of Reactor Safety here in Region IV.

MR. CANIANO: Good morning. I'm Roy Caniano; I'm the Deputy Director of the Division of Reactor Safety here in Region IV.

MR. GODY: I'm Tony Gody; I'm Chief of the Operations Branch in Region IV.

MS. SMITH: Good morning. I'm Linda Smith; I'm Chief of Engineering Branch 2 here in the Division of Reactor Safety.

MR. LOPEZ: Good morning. I'm Joseph Lopez, part of the HR staff.

DR. SPITZBERG: Hello. My name is Blair Spitzberg; I'm the Chief of the ~~Field~~ Fuel Cycle Decommissioning Branch.

MS. HOWELL: Good morning. I'm Linda Howell; I'm Chief of the Response Coordination Branch.

MR. LATTA: Good morning. Robert Latta, Coordinator for New Reactors, Region IV.

MR. ELKMANN: Good morning. Paul Elkmann. I'm a health, physics and emergency preparedness inspector in DRS.

MR. RICKETSON: Good morning. My name is Larry

Ricketson; I'm a health physics inspector.

MR. HAY: Good morning. My name's Mike Hay; I'm a chief with the Division of Reactor Projects.

MR. BONNETT: My name is Paul Bonnett; I'm with the Reactor Inspection Branch, NRR.

DR. MALLETT: Paul's here making sure that we don't do anything that's wrong.

(General laughter.)

MR. STEARNS: Good morning. I'm Don Stearns, a health physics inspector, Region IV.

MR. HAIRE: I'm Mark Haire. I'm a senior operations engineer.

MR. CORBIN: I'm just a member of the public. Carl Corbin with STARS Regulatory Affairs.

MR. STETKA: Good morning. Tom Stetka, senior operations engineer.

MR. JOHNSON: Good morning. My name is Claude Johnson, Chief, Division of Reactor Projects.

MR. BASHORE: Good morning. I'm Joe Bashore, project engineer for DRP.

MR. REPLOGLE: Good morning. I'm George Replogle, senior project engineer, DRP.

MS. RYAN: I'm Gwen Ryan; I'm a summer engineering associate.

MR. ABUSEINI: Good morning. Hasan Abuseini, reactor inspector, Engineering Branch 2.

MR. CHAMBERS: I'm Mike Chambers, project engineer, Division of Reactor Projects.

MR. LARSON: Good morning. Brian Larson, operations engineer, DRS.

MR. DRAKE: Good morning. Jim Drake, operator licensing.

MR. McBREARTY: Good morning. I'm Mike McBrearty from Southern California Edison, representing SONGS.

MR. GODY: And Mike is a member of the public.

MR. WALKER: Good morning. I'm Wayne Walker; I'm a senior project engineer in DRP.

MR. CLAYTON: Good morning. My name is Kelly Clayton; I'm a senior examiner in operator licensing in reactor safety.

MR. HANNA: Good morning. My name is John Hanna; I'm the senior resident inspector at Fort Calhoun Station.

FEMALE VOICE: Would everybody sign the sign-in sheet, please? Just make sure.

MR. GODY: We have one more member of the Region IV staff, Mr. Brian Tindell, who's operating our slides for us this morning.

MR. TINDELL: I'm Brian Tindell; I'm with the operator licensing staff here in Region IV. And if you have any needs, then myself or Tony Gody is the person to talk to.

MR. MAYNARD: Does that go for us, too, Brian?

MR. TINDELL: Absolutely.

MR. GWYNN: We have a full agenda for the day. We have some specific case studies that we think will be of interest to you. And I'm hoping that the tour of the incident response center will be of particular interest. So we'll do that right after lunch today.

Now for this first session, I plan to present an overview of Region IV, followed by Dr. Mallett's emphasis on the challenges that we have in front of us under the Reactor Oversight Program in Region IV.

In large measure, Region IV is both organizationally and functionally similar to the other three NRC regional offices. We've provided a copy of our detailed organization chart in the handout that you have in front of you; it's a very colorful document. If you studied that, you'd find that it's very similar to the organization charts for the other three regions. I plan to emphasize regional differences rather than similarities in my discussion this morning.

Now, Region IV is geographically large, encompassing most of the states west of the Mississippi

River, including Alaska, Hawaii and Guam. Our nuclear materials inspectors cross the international dateline; they inspect on platforms offshore in the Gulf of Mexico and in the Pacific Ocean, as well as in the north slope of Alaska.

We operate in all US time zones except Eastern time, and we communicate regularly with NRC offices in that time zone. I'd note that every power reactor in the region with the exception of Comanche Peak Steam Electric Station is accessed by our inspectors via airline transportation, making our location near the D/FW airport vital to our success.

Region IV has a highly talented staff with a good mix of experience and recently-hired professionals. You saw that we have one of our summer engineering associates here with us today. We actually have six of those this summer. They are the underpinning of everything that's well done in Region IV. Our training, knowledge management and knowledge retention programs, which are important contributors to our long-term success, will be discussed early in the presentation this morning because of their importance.

DR. SHACK: What fraction of your staff are sort of coming up for retirement, say, in the next five to ten years? Are you a typical NRC profile? Or --

MR. GWYNN: Well, we're fast-changing. There has been a lot of change in the mix of our regional office over the last five years. If you had asked me that question five years ago, I would have said that it was a significant percentage of the staff that is coming up for retirement, but we've had a number of retirements since then. Right now, our HR specialist -- we have 11.3 percent that are retirement-eligible in 2008 if we retain those people, I believe, 16 to 17 percent by 2009 and 20 percent by 2010. Those are the current estimates.

DR. MALLETT: I would add to that that I think over the past few years -- I've been here four years now -- we have had significant expertise walk out the door, from retirement. And so when you hear Joseph Lopez and when I talk to you in a little bit, we'll give you some insights on what we've done to try and hedge that bet, so to speak, to not lose all that expertise, such as return to annuitants, and things like that.

DR. SHACK: Yes. If you get -- how many people left have actually been on a construction site?

DR. MALLETT: There's a few of us left around. Dwight is one. I've been there, and Pat has been there, and we have several of the staff who have been. But they know they're a commodity now, so we're working to retain them.

MR. GWYNN: In the power reactor arena, we regulate 22 reactors, at 14 sites, located in ten states. We maintain both on-site resident inspector staff, as well as region-based specialist inspectors who complement and augment the resident staff. Together, they implement NRC's baseline inspection program, performing the baseline inspections, generic safety issue inspections and special inspections, in response to significant operational events.

We license the people who operate these reactors; we also maintain a robust emergency response capability, and we routinely test our ability to respond to emergencies.

DR. WALLIS: I have a silly question. You said, West of the Mississippi. Is Grand Gulf west of the Mississippi?

MR. GWYNN: It's just east of the Mississippi, but I'm talking about the states. Yes. That -- most of the states. There are some states east of the Mississippi that we regulate. And there's a couple of states west of the Mississippi that we don't regulate that are part of Region III. It's hard to make general statements, isn't it?

DR. SHACK: Especially with Professor Wallis.

(General laughter.)

DR. MALLETT: I would add that last year, in 2006, the state of Mississippi asked the Agency if they could have one regulator, because they were regulated for materials programs by Region I and they were regulated by Region IV for the reactor program. So we changed that roadmap, if you will, to have the state of Mississippi regulated by Region IV entirely.

MR. GWYNN: And we haven't done that with Missouri yet and Region III.

Some aspects of our response capability you will see today during your incident response center tour.

DR. CORRADINI: So I had -- just because you're so geographically diverse, I'm curious -- maybe it's going to come later -- about the split of effort relative to essentially plant inspections -- you were mentioning things relative to -- with sealed sources and materials that are -- have nothing to do with power production but have to do with potentially oil, et cetera. Is that going to come up later?

MR. GWYNN: No. We were not planning to get into that.

DR. CORRADINI: But just out of curiosity, is it a typical mix in terms of effort relative to the other regions, or is this an unusual region relative to materials inspections in such a geographically diverse area?

MR. GWYNN: It's -- our budget for travel is substantial, and the time that it takes for our inspectors to get to their inspection locations is substantial compared to our peers in the other regions. And that's the important point.

If I was to go from here to South Texas Project, which is in the same state as our regional office, it takes me about six hours to get there. That's a substantial investment in time for inspectors which detracts from the time that they have to inspect and causes our management team to implement some interesting differences from the other regions in terms of achieving the Agency's mission, putting our inspectors' feet on the ground for the same amount of time at those sites and still achieve the travel that's necessary to do that work.

Whether they're inspecting nuclear materials or whether they're inspecting power reactors, it -- the geographic diversity in our region is a challenge for our inspection staff and for our management team.

I'd also indicate -- I said six hours to get from here to south Texas. You can drive to south Texas or you can fly to south Texas; either way, it takes about six hours. You can only fly to Columbia Generating Station and get there in a reasonable period of time. It takes seven hours to get from here to Columbia Generating Station, and that's because the Dallas/Fort Worth airport is such a great commodity for us. It really facilitates our ability to inspect and to respond to emergencies.

Does that answer your question?

DR. MALLETT: Well, I --

DR. CORRADINI: Yes.

DR. MALLETT: Let me add something first. If you look at that colored chart that we gave you --

DR. CORRADINI: Yes, sir.

DR. MALLETT: If you look at the different divisions -- we tried to make them colors so you can tell, but I've had people tell us feedback that it's not very clear. But we tried to make it that way by the colors.

If you look at the yellow division there -- that's our materials division. We're about like the other regions in numbers of -- once all the agreement states are in place -- like Pennsylvania in Region I. I think they'll come out, and -- don't hold me to these numbers, but the region here has about 6- or 700 materials licensees.

Region II does not have a program any more; that was all folded into Region I about two years ago. And then Region II has the fuel cycle program for all the regions. They run that for the whole country. Region III has about 7- or 800 licensees. And Region I will, once Pennsylvania goes agreement, have maybe 1,200 licensees.

So there are a few differences in numbers. The main difference is in the type of licensees. In our region, we probably have more well loggers and radiographers than any other region in the country.

DR. CORRADINI: That's what I was guessing.

DR. MALLETT: We also have more agreement state programs than any other region in the country. So we have quite a few agreement states to monitor their programs to see how --

DR. CORRADINI: Since I'm new to the Committee, remind me what an agreement state is.

DR. MALLETT: It's a state that signs an agreement with the NRC to say, I will for whatever type radioactive materials I decide take over the inspection and licensing of those facilities in my state.

DR. CORRADINI: Okay.

DR. MALLETT: And most of the time, they'll take over the program entirely for like medical facilities, academics and so forth. They do not have the ability right now to take over the program for reactors in their states or for really the fuel cycle.

DR. CORRADINI: But for nuclear materials, they would?

DR. MALLETT: But for nuclear materials, they can.

DR. CORRADINI: Only nuclear materials.

DR. MALLETT: The other thing unique -- if you look at that, what I'll call the yellow division -- they probably don't like me referring to them that way, but -- if you look at that yellow color division, you see Blair Spitzberg, who's going to talk to you later. He has some unique capabilities we have here, such as the Yucca Mountain Project. And we have decommissioning reactor facilities that other regions have.

We have ISFSI facilities, Independent Spent Fuel Storage Installations, that that group covers. So we are unique in putting all those into one branch, and that seems to work well for us.

DR. CORRADINI: So you -- just to understand that, so with the licensing of PNS or -- PFS in Utah, it was your region with headquarters that went through the licensing process there?

DR. MALLETT: That's correct.

DR. CORRADINI: Thank you.

MR. MAYNARD: I think something important to know -- we've been talking about that -- as far as power reactors, it's easy to compare the regions, and the responsibilities are fairly similar. But when you get outside of the power reactors into the other, there are major differences between the regional responsibilities and regional activities in those. So it's harder to compare Region I versus Region IV on how they handle certain things, because the divisions of responsibilities are quite different outside of the power reactors.

MR. GWYNN: And you'll find virtually 100 percent of the in-situ leachate mining, uranium mining and milling activities in the United States in Region IV. And that's a growth business these days, by the way.

Let me finally highlight the significant diversity in the reactor types that reside within our regional boundaries. We inspect reactors that are designed by all of the major reactor vendors, including Westinghouse four-loop, Westinghouse SNUPPS -- the only two SNUPPS plants in the United States are located in our region. We have Babcock & Wilcox, General Electric, BWRs Versions 4, 5 and 6 and Mark-1, Mark-2 and Mark-3 containments. We have several vintages of combustion engineering design, including the only CE System 80s in the United States.

Some of the plants use sea water cooling, some of them are located on rivers and man-made lakes, and one is even located in the desert and uses wastewater from the city of Phoenix as its primary cooling supply. And so this diversity, as you might imagine, creates some interesting challenges for our staff. Our staff is up to those challenges.

And at this point in time, I'd like to turn the presentation over to Dr. Mallett, who's going to talk about some of those challenges.

DR. MALLETT: Thank you, Pat.

Before I start, I wanted to say one more thing about this organizational chart in answer to your question, Dr. Carradini, if I'm saying that correct.

DR. CORRADINI: Close enough.

DR. MALLETT: Close enough? All right. Thank you.

If you look -- our division of reactor projects is very similar to the other regions'. We are designed and divided up by plants, and each branch has a certain number of plants, with senior project engineers in that branch here in the regional office and senior residents and resident inspectors. And I can't forget the site secretaries at each of the sites where those plants are located. If you look at -- and those are indicated by blue in that chart.

If you look in the division that's indicated by the green color -- that's our division of reactor safety. And we are set up very similarly to the other regions there, who'll have -- most regions will have two engineering branches. Most regions will have a plant support branch. Ours takes care of health physics and security. You've heard some of the people here talk about it. We have an operator licensing branch.

We did something different in this region. We've combined operator licensing with the emergency preparedness. We think that gets us a good mixture of licensing and inspection in that branch, as well as they can live off each other and feed off each other for the programs that they evaluate. We've gotten a lot of good insights from both ways, from the emergency preparedness experts to the licensing group, and the licensing examiners to the emergency preparedness group. So there's --

DR. CORRADINI: So you intermingled them in that?

DR. MALLETT: So we intermingled them in that one branch. That is a difference you'll find between us and the other regions.

One other difference you'll find is that we put all our oversight of problem identification and resolution inspections, safety-conscious work environment inspections and the component design basis inspections into those engineering branches. And Linda Smith is going to talk to you later; she's probably the Agency expert --

I'll set you up, Linda.

-- for issues like safety culture and problem identification and resolution. We've found that that gives us good milage having that overseen by one branch. So that is a difference between us and the other regions.

Well, like Pat Gwynn and others, I would welcome you to Region IV. It's an honor to have each and every one of you here. I met when I was in Region II with the ACRS a number of years ago, and I think it's a good exchange. We appreciate your willingness to give your time to come out and exchange with the staff.

If you will, look at the agenda. One of the lessons that we've learned is to not just have managers talk to you; we have all levels of our organization talking to you so you can get a good mixture and feel free to ask questions of them, and to get a good view. We think it's important to you have your questions answered and understand from us how the program's operating in the reactor oversight area.

I would highlight some challenges that we see in the reactor oversight area. These are not all inclusive. I tried to pick the top five or six, but, as people have learned about me, I give sub-bullets. So the five or six may look like ten, but I've whittled them down to five or six.

These are, I believe, not in any order of importance, but I think they're important to our oversight in the Nuclear Regulatory Commission, the reactor program. First and no surprise, I think, is recruitment. We always put retention of the skills inventory down there.

What we have learned over the past several years is we're getting pretty good at recruiting the skills. In fact, these are exciting times for us. We are getting quite talented individuals because of our pay scale and because of the promotions we give people in the first three years and the incentives for schools and to pay off college tuitions.

So we are getting the cream of the crop coming to our region. And I think Gwen introduced herself earlier; she's one of those people. And we also entice them during the summer to come here as a way of recruiting them. We have set several things -- and I know Joseph Lopez is going to talk some more about this. But I think a couple of keys to recruiting and retaining people, which I think is the most important thing, is that we go out to schools now with the executive partners to those schools and recruit a diverse group of people. And we set the schools we want to go to.

We also meet every two weeks to talk about our recruitment plan and, What kind of skills do we want. Now, Dwight Chamberlain's on that committee, and he's always asking for someone. I've never gone to a committee meeting where he doesn't have the skill that he needs. But I think that has helped us to recruit some unique skills, like metallurgists, with plants aging and so forth, a big skill that we need. So we are targeting those recruitment when we go out to these schools.

I think another thing we've done for retention is -- we meet with the individuals coming on board, all along during at least their first two years here. I think the crucial period is that third year. We train them and evidence them well the first two years, then we put them out to work, and we sort of forget about them. And so we've tried to focus on ways of retaining them, and one of the ways is to meet with them and ask them what makes them comfortable in staying to work here. That's crucial, I think, for the Agency.

We have some best practices that we've developed for the Agency, and Joseph Lopez is going to talk about some of those. I think another area that's crucial and a challenge is maintaining the resident inspector pool. We are finding now that licensees are talking about building new plants and, as their work force is getting older, they're recruiting our people. And so I think that's great. I think we're all in this together, and I think we need to get the skills we need in this industry.

But what that has forced us to do is realize we have to have a pipeline for these resident inspectors like we haven't had to have before, because very quickly they'll get offered big jobs and big pay at the licensees' facilities. So we have had a significant turnover here, and we've done several things to help that pipeline, such as: We bring in people to the regional office now -- and most regions do this very similarly -- for a year or maybe two before they go out to be resident inspectors, as a pool. And we increased our project engineer pool, our people to do that, and to learn prior to going out.

The third area. This is one where --

MR. MAYNARD: I would think that would be -- one of the more challenging areas is the pipeline for resident inspectors, because, you know, a year isn't a lot of time for their development here before they go out to a site where they're remote. They're not -- I don't want to say unsupervised, but, you know, they don't have the regional management to draw upon and stuff. And that's a real challenging position, and I would think it would be a real challenge to keep that pipeline going with the type of people that can be out there away from the office and doing their jobs.

DR. MALLETT: That's an excellent point. In fact, what we've done is -- we've tried to make this balance work of people that have been around a long time and those that are brand-new. And so when we recruit, we try to recruit the entry-level individuals as well as the experienced level, and we've been very successful in that. So when they do go out to the resident site, sometimes they've had many years' experience in the industry. We've had to teach them to be a regulator, and that takes a little while sometimes. But they have had -- there's a mixture of that.

MR. MAYNARD: Yeah. The other part of the challenge is it's not always easy to find someone who's going to take a job when they know they're going to have to move in four or five years. I mean it's not a position where they can go and get settled and stay there for a long time.

DR. MALLETT: That's a big challenge. Another piece of that is we have senior residents that are very, very good at what they do, and some would like to stay out there. And so we're working on ways that we can keep them out in that pool of residents at the sites.

Other regions are in the same boat. Some people are transferring between regions, which compounds the problem. At the same time, we also bring the senior residents back to the regional office. You heard George Replogle was one -- I mentioned his name and several others' -- that have come back to help mentor people and run programs here. So you need both.

But it is a dynamic. Just when you think you have it solved, you have to work on it again. So --

MR. MAYNARD: Good.

DR. MALLETT: If I could, move on to knowledge management, the third challenge. And this has four aspects I'd like to highlight. You see them bulletized up there.

Knowledge transfer. We have learned a lot this past year in this area. We think it's very important as the skills leave the office to grab whatever we can out of their brains to transfer that knowledge to the individuals here in the office. In the past, our tradition has been to pair people with someone as a mentor-mentee relationship. That still works well, but we've now increased it, and I'm pleased with what we've done.

We started something called technical seminars, and we even have seminars in the non-technical areas now. And we hold those for about 30 minutes to an hour. The best one this past year was the one I gave -- no.

(General laughter.)

DR. MALLETT: But we have them in different areas of expertise, and we are capturing those -- at least the slides from those on our website to where you can go click on it and pull up the slides. And I think that has been a great benefit.

We even have the individuals coming in from the universities, right out of school, teaching us. And it's amazing some of the new technologies we aren't aware of. So that's quite a successful story for us.

The second bullet I have that's a key part of knowledge management is fundamentals. What I've found is we have to go back and consciously work on fundamentals of our staff. I believe industry has to do this, too. Some of the events we're seeing in industry occurring are -- you can trace back to people not having fundamentals in how they operate.

And I know you all like formulas, so I'll give you one for fundamentals: F=BRV. And my definition of fundamentals is: B stands for the Basis for why you are a regulator, and where that comes from; R stands for the Role you have as a regulator, and that's a very important piece to teach someone as a fundamental, and; V stands for your Values and, How are you going to operate.

And we have posted on our wall some organizational values -- and I know the principles of good regulation. We try to emphasize those. And what we've started doing this past couple of years is having our managers go to the training classes for the individuals to give some kind of an introduction as a way of re-enforcing those fundamentals.

And another way is: Each someone's qualified, I or Pat Gwynn and the division director responsible meets with that individual before we put them on the road to see how they're aligned with these fundamentals in the Agency.

Two other bullets I would mention: Remembering lessons learned, and event history. They kind of go together, I believe. We are working in the Agency on a lessons learned program, which I think is important for capturing those lessons learned. But I think there are people coming in to our Agency that don't even know what Three Mile Island is, or some of the lessons we learned from it.

So each year, we try to take an area. Art Howe, Dwight Chamberlain and their divisions are very good at this to focus on and try and review those lessons learned. For example, one year, we took one of the space -- I think it was the space shuttle Columbia events and looked at those lessons learned. This year, we are taking Davis-Besse lessons learned. If you'll remember, Art Howe, our division director in Reactor Projects, led that

Lessons Learned team for Davis-Besse. So I think that's very important.

Also, event history is important. We have, I think, a much better operationally experienced program in our Agency today than we had before, but remembering those events is very important. We even have, as an example, an event where we -- at Diablo Canyon, we have an environment out there in the public that is not favorable, via certain interest groups, to that plant continuing to operate. So we used to go out there and react to that, and now we're on a proactive mission to do that.

Well, one of our lessons learned from event history is that the first three meetings we went out there -- Pat and I both know -- we got tarred and feathered. So we learned from those. And we review those videotapes every once in awhile to make sure we can remember not to do the same. If we go to the next slide --

MR. MAYNARD: I find it interesting here that the -- if I were listening to a presentation from the industry or from other businesses, a number of these things are things that any business is having to deal with right now. And it's interesting to hear from a regulatory -- that the regulators also are having to deal with knowledge management and a number of these things and doing it in a way that is, I think, very successful.

DR. MALLETT: Well, I don't want to give you a false impression. We aren't there yet, but we've done some things to start on this. I believe you have to be proactive in this area.

DR. CORRADINI: So if I could just ask you one more --

DR. MALLETT: Sure.

DR. CORRADINI: Is what you're doing in Region IV similar to the other regions in concert with headquarters? Are you leading -- because I've heard one of the commissioners, Commissioner Lyons, worry out loud a number of times about this particular area of knowledge transfer or the whole issue of how you pass on key information and key experiences. So how does the region fit in with what's happening at headquarters? Or maybe this is going to happen later, so we'll just wait.

DR. MALLETT: We will talk a little bit more about it.

DR. CORRADINI: Okay.

DR. MALLETT: But I will say that, that we are -- in this area, all the regional offices are focusing on some type of knowledge transfer. Some of them have technical seminars like we have.

In our headquarters program, they are trying methods to capture this knowledge, such as videos of seminars, and we haven't linked in to that yet. We've talked to them about it, but we haven't really linked to that. I think that would be the next step, to have one Agency place you could go, instead of having to go to each regional office, to pick up maybe a topic of interest.

We are linked in the operational experience area that's run by the Nuclear Reactor Regulation office. And we can click on that area and look at operational experience. But as far as --

DR. CORRADINI: The reason I guess I'm asking that is two fold. One is: I'm curious how much of a struggle it is particularly when you have an industry which is going now a half-decade and, from the standpoint of new construction, not much has happened and, therefore, you want to capture back what you learned.

But the other part of it at least in my mind is the generational thing, that is: Who you're hiring now and how they learn is in some sense not totally different, but not exactly the same as how we might have learned or would learn. So in other words, giving a Power Point or talking to them, you might get a lot of nodding and polite grunting, but perhaps some sort of video or some sort of interaction in a different way is necessary.

And at least at the university, what we've found is going across lines in other colleges, the business school in terms of case studies, other ways in which you might want to draw them out to get them to know things. That's what I'm curious about, because it seems to me this is a really big deal.

MR. GWYNN: We -- the Agency has a knowledge management steering committee that's made up of knowledge management champions from each of the offices. Typically, the knowledge management champions are the deputy office directors, although there may be others at a lower level in the organization. For Region IV, I'm the knowledge management champion; Roy Caniano is my right hand on that activity.

The steering committee meets regularly. The Agency is preparing and developing a set of metrics that specifically focus on the knowledge management and knowledge transfer. There's a huge amount of work that's being done to address just exactly what you're interested in, Dr. Corradini.

The development of the communities of practice. These communities of practice are purely electronic. It's a way that people can involve themselves -- people with common interests with common goals and common sets of knowledge bases get together to share knowledge and experience in a way that's meaningful and in a way that will assist the junior folks in coming up to speed with the senior people.

And I think that one of the best and best-used communities of practice that we have right now is in the operational experience area that has been developed by the Office of Nuclear Reactor Regulation. But there are a large number of them, and they're really taking hold here in the Agency.

MR. GODY: This is an excellent dialogue, and we have a 30-minute session just to discuss knowledge management and knowledge transfer. That's our next session.

DR. MALLETT: Yeah. We probably destroyed most of their talk, but I think it is important. But I think it isn't -- we are consistent. I think the approaches might be a little different. Let me just quickly mention --

MR. MAYNARD: You'll find that with the ACRS an agenda is nice with prepared slides, but we tend to go where we want to and when we want to go there. And so a lot of times, your presentation will be covered before you get to it.

DR. MALLETT: Well, we are here to answer your questions, and I think that's important.

I'll just quickly mention cross-cutting issue or cross-cutting aspect. I think the point I would make there are the challenges, first of all, for industry and the NRC to get on the same page as to what's the definition of each of those terms. Okay. Industry typically crosses the two, and a cross-cutting issue is quite different than a cross-cutting aspect.

An aspect is a tag we put to a finding on an inspection report that helps us define, Do we have something that we need to review at the mid-cycle/end-of-cycle review periods to determine if it is a cross-cutting issue. Cross-cutting issue: You have to meet certain criteria. And if you have that, you tell the licensee, "You have this, and you need to address it," for example.

And so what's happening is -- industry asked us about three years ago to put more guidance out there: You have these rogue inspectors; you need to put guidance out there to have everybody consistent. So we did. Well, what that's forcing -- and I think you'll hear -- Linda's going to talk a little more about that -- is we're tagging a very high percentage -- I think 90 percent -- of findings with the cross-cutting aspect.

So the first criteria for a cross-cutting issue is the number of findings you have tagged with a cross-cutting aspect. Essentially, we wiped out that criterion because you'll meet it in almost every instance. So there's a lot of debate in the industry: Are we getting carried away.

Roy Caniano's doing a study and review of us in the Agency to see where the differences are in the regions and where the similarities are. I can tell you we looked at it last year, and we're all about the same in the number of sites that get cross-cutting issues if you look over a period of time; however, in 2006, Region IV had significantly more licensees with cross-cutting issues than the other regions. So we thought it prudent to take a look at that.

How much SDP. I put this in here for Dr. Apostolakis.

I thought you'd like that.

The real issue to me is alignment. We can do a research project on each review, a significance of findings, or we can do just a guess. And so somewhere in between lies the answer. And what we're finding in the Agency is we have to manage that process; it no longer can be just let go, because you will do research projects in some instances and you'll be untimely in your significance determination projects.

Dwight Chamberlain led a team where we evaluated this and came up with the best practices, so that all regions can use them, about a year ago. I think that's helping us. There are still areas where we need to work on it. And I put "alignment" because you will have -- if you sit in a room with all of us, you may have five or six different views of what the significance of that finding is. So somewhere, you have to decide what is the right one and move on from there.

I talked about our Diablo Canyon when I talked about effective outreach. What we learned there in external communication is we were letting events drive when we spoke to the public and when we met with licensees. And so we've decided to turn that around.

And for the past three or four years, we've met proactively with the people every year near the Diablo Canyon site. And what's that helping us in now is that the meetings are no longer as hostile as they were, and people are starting to ask questions that they should be asking instead of just listening, in my view, to the interest groups.

The last one I leave you with is what staff hears me say. They ask me what keeps me up at night in the reactor oversight program. It's that we won't turn over every rock. And Pat Gwynn's is, Trust, but verify. So I've left you with those last two bullets.

And with that, I think I've stolen about all the time away from Roy Caniano and Joseph Lopez, but I'm going to turn over the podium to them unless you have any more questions.

DR. SHACK: Just -- are we going to come back to SDP in some of the case studies?

DR. MALLETT: You definitely will. In fact, we've lined up the individuals that need to talk to you about that, and we have not schooled them on what to say. So, hopefully, you'll get the answers you need.

MR. GODY: Okay. The next session is going to be on knowledge management and transfer. Joseph Lopez is a human resources specialist, and Roy Caniano is the deputy director of the division of reactor safety.

If anybody has any needs to -- for a telephone call or to use a private room to have a discussion, Room 403 here by the reception desk is reserved for anyone who needs it. If you need to dial out, you dial a seven to get an outside line; long-distance would require a one, also. Also, there's donuts and coffee in the back. And if you'd like to have anything, feel free to help yourself.

MR. LOPEZ: Good morning, everyone. I'm Joseph Lopez, part of the HR staff. Most of my show was stolen.

(General laughter.)

MR. LOPEZ: So we'll make this quick.

MR. MAYNARD: That's all right. I think you'll find that we'll probably still have some additional questions.

MR. LOPEZ: That's good. I hope I can answer them or at least provide some insight.

I want to start off here with the Region IV management team here. They actually set the goal to institutionalize the KM activities, Knowledge Management activities. They wanted to make it second nature, make it part of our every-day decision making. It also started out with hiring the right people, as Bruce mentioned earlier.

We're going to cover three things. And in the interest of time, I will bypass a few of the items. If you have interest in them, let me know, and we'll talk about them in detail. But I want to cover communication, implementation and staff development.

On the communication side, we created our actual knowledge management plan. In this plan, it actually identifies actions that we've taken to date; it also identifies prospective actions that we're considering once we get the time and the budget for them.

MR. MAYNARD: I'd like to go back just a minute to a question that Michael Corradini asked just earlier.

MR. LOPEZ: Yes, sir.

MR. MAYNARD: Now, it's my understanding that between the regions and NRR there isn't a common knowledge management plan; each region has been doing their own. You guys -- you talk to each other, and you coordinate, but each region's going to have some specific needs. So I don't agree with having one plan that fits all.

MR. LOPEZ: Yes, sir.

MR. MAYNARD: But is my understanding correct that you coordinate with the others but you do have your own knowledge management plan to fit your needs?

MR. LOPEZ: Absolutely, sir. We -- the steering committee actually meets once a month. We actually have a dashboard that identifies the projects that each region and each office is working on. Not everybody is working on the same items, because every -- it's, you know, as you go. Does that answer the question?

(Pause.)

MR. LOPEZ: Moving on to our next communication plan is our human capital management plan. The objective of this plan: it actually identifies tools and resources for our managers to help manage the human capital here at Region IV.

PBPM: That's actually Planning, Budget and Program Management. These are regular meetings with the branch chiefs and above, with the focus on aligning mission needs with the skill sets.

Bruce talked a little bit about the resource planning meetings. This is the bi-weekly meetings with the division directors, deputy regional administrator and regional administrator with HR. And the entire intent of that meeting was to manage the human capital.

Current events meeting. The regional administrator and directors actually meet monthly with the entire staff to update them on issues facing the Agency.

Let's see. On the implementation side, Region IV actually took the lead in creating the "Recruitment and Retention Best Practices Booklet for Supervisors." I'll pass these out real quick.

(Pause.)

MR. LOPEZ: And this booklet -- it's essentially a quick guide for supervisors to rely on as to what tools are available, what tools are out there on the website. It gives them some helpful hints. So take your time and review that, and if you have any questions on that, we can chat about it.

So just when you have your retention problems, where are people going? Are they going to licensees? Is that the -- actually, let me see here.

The figures for '07. Our attrition rate was 11 percent. Keep in mind that 5 percent of that was transfer to other regions or headquarters. 6 percent were actually retirements and resignations. I want to say it was about

2-1/2 percent that were resignations, but I don't have a clue as to where they --

DR. CORRADINI: Just to follow up on that --

MR. LOPEZ: Yes, sir.

DR. CORRADINI: I'm not sure what the federal rules are. But if you have somebody that essentially leaves the Agency, are you allowed to ask anything more than their opinions of how life went when they were here? Can you ask where they're going?

MR. LOPEZ: Yes, sir. We actually have an exit interview.

DR. CORRADINI: Okay.

MR. LOPEZ: And we try to capture that information. You know, some are for personal reasons. The majority are for personal reasons.

DR. CORRADINI: Well, I guess that kind of follows up on Bill's question about where they're going and, Why are they going there. You're getting some generic --

MR. LOPEZ: Yes. We as an Agency try to capture that information. We even actually try to capture it from resident inspectors when they're leaving the resident inspector program, as well.

MR. MAYNARD: As far as those going to the industry, my gut feeling is that probably at this point there's more coming from the industry to the NRC --

MR. LOPEZ: NRC.

MR. MAYNARD: -- than the other way. And most of those might be back in headquarters, but it goes both ways. I've seen a lot of industry people within the NRC and then some from the NRC going to industry. So --

MR. LOPEZ: I really don't have a good feel for the figures on those. But --

DR. MALLETT: I can tell you the people who go to industry -- it's usually for one of three things that I've found. Location: They don't want to relocated, as you've said. They want to stay in that part of the country. Salary. We do pay very good, but the industry sometimes will trump that, and we can't go as high.

Or the third is that they don't like the work that we do from being on the road and inspecting all the time. They want to get into design work or some kind of hands-on engineering or health physics. Those seem to be the major reasons when I've talked to people about why they're leaving.

MR. LOPEZ: Going back to the list, biweekly reviews of operational experience. After our reactor status meetings, we actually have our senior staff members present and provide issues. They stick around after the meetings to answer questions.

So I'll move on to the knowledge management corner. We actually created a site on the Region IV website. On this site, you'll find the human capital management plan, the knowledge management plan, as well as the slide shows for the previous knowledge management seminars. And Roy's going to get into the knowledge management seminars here in a bit.

Management Information Icon: We in HR created this icon for the branch chiefs and above. What this does is -- it provides real-time data. It's everything from staffing planning to awards history, training and budget, so that the managers are able to make real-time decisions. Bruce and Pat talked a little bit about the post-certification interviews that they have with the employees.

And let's see. Moving on to staff development, we have a Region IV management library we created a couple of years ago, with the intent of providing books and materials to all employees. It's a self-checkout. We also have started focusing more management training in the region. We did a Train the Trainer for the four roles of leadership. So we have one of our senior staff members here that actually provides the training about twice a year to our managers.

Let's see. I'll bypass double encumbering and rotational assignments.

Let's see. Pat talked a little bit about reverse mentoring or what we're calling reverse mentoring. It's where the engineering associates or summer employees come in and actually prepare presentations for our seasoned staff.

MR. GWYNN: If I could just interject on that?

MR. LOPEZ: Yes, sir.

MR. GWYNN: It's really remarkable the kids that are coming out of school. And I'll -- you know, my gray hair. But the people that we're hiring directly out of college can teach us a lot of things. I learned four times four when I attended Purdue University. Today, they don't think about four times four. And so there are tools and techniques that they can teach us that are extremely valuable for our employees to know.

And so just yesterday, our summer engineering associate trained us on how to use a tool that she developed as part of her summer project that will be useful for our inspectors in the field looking at heat transfer problems. And so it was a very appropriate thing, I think, for us to use, this reverse mentoring process, to push up to the more senior people new techniques that have been developed since we graduated from college.

DR. CORRADINI: If I just could --

MR. MAYNARD: There's a few others of us who remember Fortran.

(General laughter.)

DR. CORRADINI: So I had a question about that. So you have -- I'll call them -- I'll use the term, Summer interns. You have a term I've forgotten already.

MR. LOPEZ: Engineering associates.

DR. CORRADINI: Okay. So at the end of their time, do you get a feedback from them on ways that you could have done better in terms of training, that is: Asking them what sort of ways are most effective that they can learn about the Agency and the industry, et cetera?

MR. GWYNN: Just -- I think it was a week ago they delivered to us a combined paper. All of them got together and conspired to tell us how we could do a better job --

DR. CORRADINI: That's good.

MR. GWYNN: -- in sponsoring them for the summer and maximizing the value of the time that they spent with us. And that was very useful feedback, and we thank them for it.

DR. CORRADINI: Yeah. The only reason I asked it in that way is that sometimes -- we always think we know how the younger folks learn, and I'm convinced that we don't. But if you ask them, they'll actually give you ways that you would have never thought of to actually provide information and get them to be more motivated into what they learn.

MR. LOPEZ: Along those lines are auditing and introducing training courses. Our senior managers here, Bruce Mallett, for example, actually sat in a financial management course. They -- it was important in that the instructor was teaching us how things worked, but Bruce was able to relate or give us the relationship to the NRC and why we have to get down these policies. So it's advantageous to have senior managers sit in on those.

The SES Candidate Development Program and the Leadership Potential Program. Region IV continues to support employees and the employees in those programs with rotational assignments and fill in their positions so they can go on these rotational assignments.

Before I hand it over to Roy to discuss knowledge management seminars, do you all have any questions on any of these, or do you want to chat about it?

MR. MAYNARD: Do you get much use out of the management library?

MR. LOPEZ: I believe so. We were initially. I haven't checked the books lately.

DR. MALLETT: Well, we --

MR. MAYNARD: I asked for a reason.

DR. MALLETT: It just depends. If we -- the books will collect dust. If we have a class that we're focusing on, like the four roles of leadership -- we talked about "The 8th Habit," Steven Covey's book. So then you'll get people looking at the book. But you have to emphasize in a class or some setting or you won't -- you'll get very few people checking them out.

MR. MAYNARD: Yeah. My experience with these has been that, you know, it may be that one or two people use
it -- and very few others, but if you start keeping track of its usage and, allo f a sudden, the usage picks up because people think you're monitoring for that, but --

(General laughter.)

MR. MAYNARD: It's a useful thing to have, but I haven't found that it works as well as what it maybe could.

MR. LOPEZ: Any other questions?

(Pause.)

MR. LOPEZ: Roy?

MR. CANIANO: Thank you, Joseph.

Good morning again. I'm Roy Caniano; I'm the Deputy Director of the Division of Reactor Safety here in

Region IV.

What I'm going to discuss today -- you've heard the name "knowledge management sessions" a couple times this morning. Bruce Mallett referenced it as the technical seminars, and Joseph chatted a little bit about it. I'm going to get into a little bit more of the specifics.

In Region IV, we initiated these sessions about mid-2006. To date, we've had about 12 sessions. The presenters are not just limited to our seasoned staff. That's pretty much how we started out: By having the ability to have some of our senior staff, folks that have been there and that have done that, talk to our newer folks. And it evolved over the past year, I'd say, to where the presenters actually include not only the senior staff, but include senior management.

Bruce mentioned that he had given a presentation just recently on a trip that he had to Japan. We also have our NSPDP participants provide topics for us to learn from. Our summer hires. Pat had mentioned Gwen yesterday had done a presentation to us associated with heat exchangers.

Last year, we had an individual, Micah Bikerra [phonetic], who was one of our summer hires here. We were very fortunate, by the way. We have hired Micah now, and he is part of the NSPDP program. He gave a fantastic seminar associated with metallurgical properties with some real-life examples.

We've had great success with our rehired annuitants. We had two of them this past year that gave very good presentations to us -- one happens to have an area of expertise in fire protection; another one in the area of ISI and ASME codes -- and gave very good presentations to our staff.

Tomorrow, we're having -- we've mentioned Davis-Besse. There actually is a knowledge management session that we're sponsoring tomorrow associated with Davis-Besse and maybe some comparisons to the Challenger event. So we have actually one of our resident inspectors who is coming in tomorrow to give that presentation, and that's also going to be sponsored by our director of reactor projects. Art Howe is going to be facilitating that effort.

MR. MAYNARD: So you're going to focus on the NRC role in Davis-Besse?

MR. CANIANO: Yes. But, again, making a comparison and some of the similarities.

So some of the topics that we've included in some of our seminars. I gave a presentation last year on an AIT that I had the opportunity to lead back in the early '90s at Point Beach that was associated with a hydrogen burn with a dry cask storage device. We gave a presentation here of an IIT that happened at TMI that was a security event that happened back in the '90s.

We were very fortunate. One of our security inspectors here we hired from the industry. He happened to be a security officer at TMI. He was actually the individual that, quote/unquote, "Captured the bad guy." So he gave about an hour presentation to us giving a perspective of what security was like back in the '90s during the time frame of the TMI and what has changed in the industry and what has changed in the NRC. So that was a very good seminar.

Again, I mentioned the fire protection. We had one on interpreting electrical diagrams, ASME code interpretations. Pat Gwynn gave a presentation on the Chernobyl event.

What we try to do is limit the discussion to about 60 minutes, and then we open it up for Q's and A's afterwards. The attendance is fairly well. You know, considering that we are a regional office where we do have a lot of our staff that are out at the resident sites, we will still get 30 to 50 people in attendance to these seminars. We also open them up via telecon now to the resident inspectors so they can call in and they can listen to the dialogue. And again, we've been fairly successful with regard to that initiative.

You mentioned -- Joseph had mentioned, I should say, the KM Corner that's on our Region IV web page. We want to --

Yes?

DR. CORRADINI: Could I just one question?

MR. CANIANO: Sure.

DR. CORRADINI: Just to go back to the ones that you identified as being so unique, so do you capture them and pass them on to the other regions so the other regions can share in your presentations?

MR. CANIANO: Not yet. We have not done that yet. But -- Pat mentioned the steering committee that we're all members of. That's actually one of the parts of the dialogue recently that we've had: How are we going to end up sharing that information. Now, we do post all of the material on our web page, and that's available to the other regions.

The ASME -- let me back up a second. You made a good point, the ASME presentation that we had. Actually, we shared all of our slides that we used in that and the complete presentation was given to Region III, because they were doing a similar seminar.

DR. CORRADINI: Okay. Thank you.

MR. CANIANO: The postings that we put on our web page. It's the responsibility of the individual who does the presentation to make sure that HR gets copies of all the slides and the presentation and -- again, so we can put them on our web page. So for those staff that were not available to attend the session, they can at least go to web page and then take a look at what the presentation consisted of.

Now, there's something else that we do, also. We have a morning meeting here. It's predominantly for the reactor program, but it's Monday or -- it's every day at ten o'clock.

Every Monday, we set aside a little bit of time after that meeting, and -- we have three senior risk analysts here in Region IV. And what they do is -- they stay back from the meeting, and we give them the opportunity to talk to some of our newer staff about technical issues. It could be an event that we just got through talking about. And the SRAs take the initiative and the lead to discuss the technical aspects of the event.

We talk about operating experience with our new staff. And for the new staff that are in the office, if they're not at a training session, it's well attended. And I would say on the average we may have six to eight people that stick around after that morning meeting and talk to our senior risk analysts, again, about technical issues, just to gain an understanding of, you know, What is the significance of this event that we just talked about. So that, I think, works fairly well.

We recently did an effectiveness assessment. I indicated earlier we've been doing these seminars for about a year. About two months ago, I sent an all-region e-mail out saying, It has been a year now; we need some feedback; because we want to continually improve in our KM sessions, give us some feedback.

I'm real happy to say that the majority of folks that responded were very, very positive on the KM sessions -- in particular, some of our newer staff, who get that opportunity to learn from staff that have been there, that have been involved in events and technical aspects.

Some of the things moving forward. We don't want to limit our knowledge management sessions to only the technical aspects. Pretty much, that's what our business is about. But we're going to try to open them up to non-technical aspects, too.

Joseph and I were chatting just the other day. And from an HR perspective, there are some things we can open up that would be non-technical in nature but, again, would be sharing of information for a lot of our newer staff. Another thing that we're going to try doing is videotaping the sessions.

So in addition to having the slides that would be available on our KM Corner on the web, we'll actually be able to have a video. So again, staff that were not able to attend it in person not only can go to the KM web page, but they can also take a look actually at a video. We are having a DRS counterpart meeting coming up in the October time frame, and we're going to actually float the balloon out there and try videotaping that entire session and -- again, to make it available.

MR. GWYNN: You ought to let your students set up some videoconferences for you.

MR. CANIANO: They can do it by --

MR. GWYNN: Let's do it cheap and easy.

MR. CANIANO: Exactly.

Any additional questions or comments regarding that?

DR. MALLETT: Before Roy leaves us, another area we're looking at, but we haven't gotten too far yet. I've talked to the industry reps and the vice presidents of the plants and told them, Why don't we get together; you have seminars, and we have them; why can't we share expertise. And they're game to do that; we just haven't figured out a way to structurally do it yet. But I think that would be great if we could share those.

MR. MAYNARD: I agree.

Thank you.

MR. CANIANO: Okay.

MR. MAYNARD: I think we're ready for Reactor Oversight Process, Case Study One.

MR. GODY: The first case study under the reactor oversight process is going to be conducted by John Hanna. John Hanna currently is acting senior project engineer in the division of reactor projects; his permanent position is senior resident inspector at the Fort Calhoun Station.

The Room that's -- Room 403 does have a laptop. And if you're an NRC -- if you have NRC access, you can check your e-mail.

MR. HANNA: Thank you, Tony, for that introduction.

Can you hear me in the back?

(Pause.)

MR. HANNA: Okay. Great. As Tony said, my name's John Hanna; I'm the senior resident inspector at Fort Calhoun Station. My intent here is to talk a little bit about the ROP and how we used it during the Fort Calhoun "mega outage," as we called it, or, "the mother of all outages."

(General laughter.)

MR. HANNA: During the presentation, I will touch briefly on the scope of the outage. I'm going to use some pictures to talk about that. The outage, I would say before I get going, was not the challenge to the licensee that one would have expected. It was anticipated that there would be a large number of issues associated with the major components, namely issues with design, fabrication, installation, testing. And also, that -- we anticipated that the licensee would be challenged with the number of contractors that they had. I think --

DR. BONACA: Could you describe briefly what the mega outage was?

MR. HANNA: Well, that's what I'm going to come to.

DR. BONACA: All right.

MR. HANNA: Through the slides, that's -- the first topic that I'll cover is the scope of the outage. And I'm going to describe exactly what they did. And then, secondly, we're going to get into right here, the substantial cross-cutting issue, how that came out of the outage, and then moving them to Column 3.

But if you will, hold that for just a moment.

DR. BONACA: Okay.

MR. HANNA: Those issues did not arise associated with the major components and oversight of contractors. Rather, the licensee's performance during the outage, and as was revealed during the outage, was challenged in different areas and, as I mentioned, resulted in these two items. Lastly, we'll try to reserve as much time as possible for your questions.

DR. BONACA: Can you move the microphone closer to you, please?

MR. HANNA: Sure.

DR. BONACA: Thank you

MR. HANNA: Is that a little bit better?

DR. BONACA: No.

(Pause.)

MR. HANNA: Better?

DR. BONACA: Yes.

MR. HANNA: Okay. Great.

As I said, the first few slides are intended to explain in broad terms the scope of the refueling outage. One of the items that OPBD needed to be successful with -- and OPBD, by the way, is the licensee for Fort Calhoun. They needed to clear room in the spent fuel pool to allow full-core offload. Of course, with the major component replacement, they had to do a full-core offload.

In order to achieve this, they had to complete their first ISFSI campaign, the initial ISFSI campaign. Chronologically, it was the first major project to be undertaken by the licensee.

As we can see here, these are the horizontal storage modules. These are the canisters in which the fuel went into. This is the transportation module. Over here we see --

DR. BONACA: What is an ISFSI?

MR. HANNA: That was the ISFSI.

DR. BONACA: What is an ISFSI?

MR. HANNA: Independent Spent Fuel Storage Installation.

As we see here, the new components are being barged up the Missouri River. This was immediately prior to their offload at the plant. Here you can see the generators. Right here is the reactor vessel head, and then right behind it is the pressurizer. In addition to the replacement --

DR. SHACK: Now you probably understand a little why the mega outage.

(General laughter.)

DR. SHACK: Those are all very major components.

MR. HANNA: And that's just a little portion of what they were doing. Actually, my next --

Thank you for the segue.

What I was going to mention was: Along with those components, they also replaced the main transformers and they also replaced the containment sump screens, so with much larger cross-sectional area to address the NRC bulletin on that issue. And by the way, these components were shipped from MHI in Japan. So they had a very long, tortuous journey to get here.

DR. SHACK: And these are combustion engineering steam generators. Right?

MR. HANNA: That's correct.

MR. MAYNARD: That's a combustion engineering plant.

MR. HANNA: That is correct.

Here what we're seeing are -- one of the next phases of the outage after the reactor was shut down. Now, this is the Brock hammering of the existing containment concrete in preparation for establishing the equipment opening.

By the way, a couple of interesting items of note. This platform that you're seeing that these folks are working on is approximately 50 feet up in the air. Secondly, although the old reactor vessel head was in very good shape, the licensee decided to replace it at this time because they didn't want to do this again.

Thirdly, I would point out these voids that you see right here. Remember those. I'm going to come back to that in the outage. These were voids as they were punching through, and with this reinforcing bar -- and by the way, just right there is the containment liner -- they found voids in between these -- essentially, they're like two-by-fours. They're reinforcing supports.

One of the questions that I noted that you all had asked that we address is -- involved the training toward the development of new inspectors. I'm mentioning this here because we had several relatively new inspectors come to the site and assist us with our inspections. We use the inspection program as a developmental opportunity for these newer folks.

For example, when voiding was found in the containment that I just alluded to, it provided opportunities for folks with knowledge of civil engineering and concrete pouring, et cetera, to help us understand where the problems might be. And we in turn, you know, indoctrinated them in sort of the NRC way of doing things of inspecting. So it was a win/win. We benefitted from their civil experience and their knowledge with concrete, and they learned how to conduct inspections, engage the licensee, et cetera.

MR. MAYNARD: How long did this whole operation take?

MR. HANNA: If I remember right, it was 89 days and 23 hours --

MR. MAYNARD: So three months?

MR. HANNA: -- from start to finish.

MR. MAYNARD: Three months?

MR. HANNA: That's correct.

MR. MAYNARD: That's still incredible.

MR. HANNA: Yes. And that was actually ahead of schedule. The licensee completed -- I believe it was on the order of a day or maybe a couple of days ahead of schedule, depending on which schedule you were looking at. But --

MR. GWYNN: This was the biggest construction operation at an operating plant that has ever occurred in the United States.

MR. HANNA: That's correct. And it may also be within the whole world. If you're looking at the total number of major components, I don't think anybody has ever done this before, ever.

So I would also point out here that Region IV used a lot of operational experience from plants like ANO and Turkey Point to inform our inspection planning and to respond to issues when they arose, such as the containment voiding that I was talking about, much in the same way that OPPD benefitted from the use of Bechtel as their contractor, which had done many other major projects, we benefitted from using operational experience from other sites within our region and from outside our region.

Here we have a picture from inside containment. Obviously, what you can see here is the reactor vessel had and -- some ventilation, ducting, the polar crane, and whatnot. I would also point out that, as you see these folks working on top of the reactor vessel head, there's a headstand down below. Keep that in mind. That'll be an issue that I'll address later on.

DR. WALLIS: So this concrete has re-bar in it?

MR. HANNA: Yes, sir. There's many, many layers that --

DR. WALLIS: How do they re-attach the re-bar when they've cut it out?

MR. HANNA: How do they attach it? They --

DR. WALLIS: How do they re-attach it to make a continuous meshing --

MR. HANNA: Right.

DR. WALLIS: -- which is it's intention, all the way around?

MR. HANNA: They have a fusing mechanism. They basically encapsulate the two ends of the re-bar. And I'm not sure of the exact chemical, but it's a magnesium-type fire.

DR. WALLIS: And they weld it up again?

MR. HANNA: They flash-fire. It burns very brightly, very hotly and welds the --

DR. SHACK: It's a thermite reaction.

MR. HANNA: I -- if you say so.

DR. SHACK: It's a thermite reaction.

MR. HANNA: Sure.

DR. SHACK: MIT students do street cars to run off of --

DR. WALLIS: That's right. Do they still do that?

MR. HANNA: Oh.

DR. WALLIS: When did they last do that at MIT?

DR. SHACK: A long time ago, street cars ago.

DR. CORRADINI: And you weren't expelled?

(General laughter.)

MR. HANNA: Now here, this is the second portion of the presentation. I wanted to talk about the Fort Calhoun substantial cross-cutting issue.

As I alluded to before, it was anticipated that there would be lots of problems that would occur with design fit-up of the major components, especially given the fact that this has been a problem for other licensees and that this licensee had problems with the control of contractors during the previous outage. Counter-intuitively, many of the problems that we did find were in areas where the licensee had historically performed well.

And some of those issues, which resulted in finding them in violations in the third and fourth quarters, included an inadvertent pump-down of an intake bay that resulted in it being pumped dry and having less than the minimum number of raw water pumps that was needed. Another example was over-pressurization of the CVCS and HPSI piping when procedures were not followed. And there were several other examples that I -- which I won't go into.

The common denominator for these issues was human performance, specifically peer checking. When we collected all of these findings at the end-of-cycle meeting --

DR. WALLIS: I have a question.

MR. HANNA: Yes, sir.

DR. WALLIS: How do you over-pressurize HPSI piping? I mean it's already high-pressure piping, and your pumps go to a certain level. How can you ever go beyond that level?

MR. HANNA: Yes, sir. HPSI piping at or -- HPSI system at Fort Calhoun is what probably would be considered an intermediate head system at, say, a

Westinghouse facility. It's about 1,400 pounds or so. So what they were doing was pressurizing with the charging pumps or actually positive displacement pumps. And that's what caused it. That's why it's much higher than the 1,400 pounds.

As I was saying, the common denominator of many of these issues was human performance. We did notice a pattern or a trend between these findings. As the ROP requires, we evaluated these findings against three criteria in the manual, Chapter 305, and these were the criteria that Bruce was alluding to earlier, and we found that there was a pattern. The commonalities of these --

DR. MALLETT: John?

MR. HANNA: Yes, sir.

DR. MALLETT: Why don't you reiterate what those three criteria are?

MR. HANNA: Okay, absolutely. I have them book-marked right here.

The three criteria are -- the first one's multiple green or safety-significant findings in the assessment period with documented aspects of human performance. In this case, at the end of 2006, they had -- Fort Calhoun had 13 findings. So they certainly met that criterion.

The second criterion was contributing causes had a common theme, collaborated by more than three findings from one -- excuse me more than three findings and from more than one cornerstone, except with mitigating systems. We met that. There were four or five, if I remember right, in the area of human performance with a sub-aspect of work practices, self- and peer checking. A lot of these findings and events I'm describing here were a result of self- and peer checking.

And lastly, the Agency has a concern of licensee scope of efforts or progress in addressing the cross-cutting issue. And that was also met. We did not feel that the licensee had their arms around the issue, so to speak. And as I --

MR. MAYNARD: Does the process -- I mean this was a very large-scope outage. And a lot of it was being done proactively. Some was required -- it was going to be required at some point, but, you know, some proactive measures being taken, and, yet, find additional issues in a very complicated action. How does the reactor oversight process kind of account for that, or does it just say, I don't care if you're doing a thousand things or one thing if you meet this criteria?

MR. HANNA: With respect to human performance or other cross-cutting issues, the ROP is -- it does not care, for lack of a better word, what was done within that inspection year. It does not give credit for folks that tend not to be ambitious and do extra things. So if -- I don't know. That's probably not the politically correct way to put that.

DR. MALLETT: Okay. John is done. We'll go on to the next one.

(General laughter.)

DR. MALLETT: That's an excellent answer. I would just add that -- I'm Bruce Mallett, again. I would just add that at the mid-cycle and the end-of-cycle reviews we do every six months, we sit around a table, probably 15 to 20 of us, and evaluate this. And that third criterion is the hinge pin. It's, Do you have an underlying concern.

And sometimes we'll say, Well, we have a number of findings, but when you look at what they did overall, it doesn't seem like it would be worthy of that. And I -- but that is a judgment call.

MR. HANNA: Yes.

Dr. MALLETT: And John's right. It -- the process loads it all in, but you have to have the people sitting around making that judgment. That's why that third criterion is so important.

MR. MAYNARD: And I'm not asking for your answer in this case or what -- I just -- I do think that's important in the process, because we don't want the process to discourage people from doing things just to minimize.

DR. MALLETT: Well, what I think is an interesting dilemma --

And I'm sorry, John; I don't mean to take over.

-- is the industry is pushing more and more for less and less judgment. Well, my concern is that third criterion is very, very important to have that judgment. And essentially by them pushing, we've now taken away the first criterion, and almost everything is tagged with a cross-cutting aspect. And so it's interesting; I think there's a balance there that needs to be maintained.

So I'm sorry, John.

MR. HANNA: Oh, no. That was actually an excellent segue, because where I was going with this was, aside from meeting these three criteria, there were other things that helped inform us on this third criterion or that helped convince us that it was appropriate to give them a substantial cross-cutting issue in this area.

Specifically, these issues involved only one or two departments, operations and health physics. They were very tightly defined. These occurred within a very narrow window temporally, and all involved unusual plant configurations or undesirable consequences. So you take these three criteria, and we met those. And the fact that it was very tightly defined -- we had reason to believe that -- essentially, it's not data scattered all over the place. This is a very narrow area.

I'm seeing some confused looks over there. Any questions on that before I go to the next slide?

DR. WALLIS: Well, we're confused about this microphone problem.

MR. HANNA: I can just get rid of the mic and just project if that's better.

MR. GODY: I can --

DR. SHACK: In a larger question, I mean when we looked at this cross-cutting issue, one of the concerns was that everything would become a cross-cutting issue. And in a larger sense, have you found that happening?

MR. HANNA: I don't know that I can answer that, as this is more programmatic than a policy issue.

DR. MALLETT: At the risk of getting the reverberation again, I'll turn this on. But I do think what we found is that's a definition of a cross-cutting aspect versus an issue. I think that this study that Roy Caniano's doing as the lead for us will help us answer that question. But I'm -- my --

DR. SHACK: Why does it sound as if we're down to Criterion 3 that keeps us from going?

DR. MALLETT: Two and Three. Two is you have to have a common theme. And some of them don't have a common theme in them. But Three is the major one, the hinge pin. But I do see us driving towards cross-cutting aspects in most of the cases.

There is a table we've done -- and I think Roy has it -- of all the number of findings that were issued in all of the regions. And you can see and look at last year and the year before and this year on those that are tagged. And the percentage is going up dramatically. But we changed about two years ago our guidance to the inspectors of how to tag something with cross-cutting aspects. So I think we're getting what we're asking for.

And so my answer to your question is I don't see a trend of more issues; I do see a trend of more aspects -- findings tagged with that aspect. Does that --

(Pause.)

MR. MAYNARD: Let's go ahead and move on. We're running just a little bit behind schedule, and I realize that we're responsible for that.

MR. HANNA: Yes. And I have copies of the inspection reports from the third and fourth quarters if you're interested in taking a look at those. And those were the ones that flagged these others.

Here we have the containment spray valve at Fort Calhoun Station. This is one of two unique AOVs at Fort Calhoun that admit containment spray water to headers. This valve is unique because it has a V-ball; you can see it right here. It's actually a sphere, if you will, and it rotates on a spline.

That spline shaft results in dozens of different possible configurations for this V-ball, and this ball was installed almost exactly opposite of its desired position during the spring 2005 outage and went undetected for nearly a cycle. It was self-revealed during the fall 2006 outage, when reactor coolant system water became -- started raining down in containment as the plant repositioned into Mode 5 and put -- and shut down the cooling/heating chambers in service.

The safety consequences for having this valve installed backwards were that it would virtually eliminate any water being sprayed from that header for that train and, secondly, if the licensee were to respond to an accident which would not allow containment entry, operators would have induced the LOCA themselves by transitioning to shutdown coolant. Say they have a small break load versus one -- they put the shutdown coolant exchangers in service, and they're stepping through it, but this valve, being installed backwards, would then induce the LOCA, and that made the safety consequence of this issue much higher.

By the way, I had also mentioned that there were significant amounts of operational experience we used when evaluating this issue. This is a problem that has occurred with other licensees with these people.

We ultimately concluded that this was a white violation, and this was the first white violation that was finalized in the second quarter of 2007.

DR. ABDEL-KAHLIK: This valve is one of how many?

MR. HANNA: There's two.

DR. ABDEL-KAHLIK: How do you know that both of them are okay?

MR. HANNA: They did inspections, exten~~ded~~t of condition inspections, when this condition was found to verify that the other one was installed properly.

One of the issues that we have with the licensee, if I can go back here, is that they didn't have a testing -- an adequate test to make sure that that was installed correctly. If they had done a visual examination; if, say, they had pressurized the line with air -- obviously, you don't want to spray down the containment with water to test the valve, but they could tested it with air or any number of things they could have found that it was inadequate. They did check the operate train before they went further.

That was -- the previous slide was the first white. This is the second white. As you probably know, a licensee reports safety system functional failures, and the criteria for the green/white threshold is greater than five. The performance indicator is somewhat different from the others in that it relies on the reporting criteria as specified in NUREG-1022.

During the second quarter, the licensee reported two more safety system functional failures, which took the PI white. And I can go into any of these individual safety system functional failures. Remember the reactor vessel head scan. I believe that was Number 2 and Number 3 along here. Basically, they found that reactor vessel head scan was not seismically qualified. So in a seismic event, it could possibly tip over and take out both trains of RHR. That's why that was included.

By the way, the quality of this graphic isn't exactly the highest. I had to ad lib this a little bit because at the time that we created these slides for the presentation, our public website had not yet been updated with the new information.

So based on two white inputs, this caused us to move the licensee to Column 3 of the action matrix. The actions taken so far by the Agency have been, as I mentioned, moving them to Column 3, informing them with a revised assessments letter of that action, and we told them in that letter that we would perform a 95002 inspection and with the date to be determined. Essentially we have to wait for the licensee to tell us that they're ready for that, and then we will schedule it.

Actions taken by the licensee. They formed a performance improvement team, and they started developing a plan and dialoguing with industry peers and started talking about a scheduled date.

That is all I have for this presentation. I'm happy to take any questions or comments.

DR. SHACK: Do they have their new sump screen in place?

MR. HANNA: Yes. That is correct.

DR. SHACK: Has it been formally reviewed as acceptable, or is it just there at the moment, and then they're still submitting packages on it?

MR. HANNA: I'm not sure of what you mean by, Formally reviewed. If --

DR. SHACK: Well, I mean if --

MR. HANNA: -- inspected by --

MR. MAYNARD: I don't think any of the industry screens have been accepted for Generic Issue 191 --

MR. HANNA: 191. That's --

MR. MAYNARD: -- to put them in. But whether they're adequate or not still hasn't been determined.

MR. HANNA: I do know -- that is correct. I do know the licensee is still doing whole model testing of the screens. Now, what they had installed was intended to be a temporary fix to allow them to continue to operate until the spring 2008 refueling outage. They had asked for an extension, I believe, to do nothing essentially until 2008 replacements. We said, No; we really need to do something with this event.

This has been an ongoing issue. We've known about it for a long period of time, and we --

DR. SHACK: They had a 60-square-foot screen.

MR. HANNA: They had the smallest screens in the country, and they were a concern for the Agency. And it was necessary in the Agency's view for them to move forward with a larger screen in the near term while they were studying what was really needed in the long term.

DR. SHACK: Oh. So --

MR. MAYNARD: I think they planned to do more later, depending on the outcome of the testing and everything.

MR. HANNA: That's correct.

MR. MAYNARD: But this was just an interim measure, not intended to be their final measure, as I understood it.

MR. HANNA: That's correct.

DR. MALLETT: Well, what they have done is -- they've increased their surface area. And that's very important to have that done at this point in time.

MR. HANNA: Right.

DR. WALLIS: I think it's still in the same place. Isn't it? It's just bigger, but it's still in the same location? Isn't that --

MR. HANNA: That is correct.

DR. MALLETT: It still has the same entrance into the sump; it's just that they expanded out the path before you --

DR. WALLIS: It's not one of these things that goes all the way around, though; it's just much bigger, but in the same place?

MR. HANNA: It starts to curve around --

DR. WALLIS: It starts to curve around at the -- okay.

MR. HANNA: -- and it doesn't make very large of an arc, but it does start.

Sixty square feet you mentioned. That was actually both screens, 28 feet individually.

DR. SHACK: Yes.

DR. WALLIS: It's a small garbage can.

MR. MAYNARD: Okay. Well, we might want to come back to some of these things, go through some other case studies and stuff. I'd recommend now that we go ahead and move on to the ROP best practices.

MR. GODY: Okay.

Thank you, John.

MR. HANNA: Okay.

MR. GODY: Our next speaker will talk about ROP best practices. His name is Michael Hay. Michael is the chief of our reactor projects branch, and he has several of our boiling water reactors in that branch.

MR. HAY: Well, good morning. My name's Mike Hay. Just to give you a quick background of me so that you can maybe share with me my perspectives. I've only been a branch chief now for about eight months; prior to that, I was a resident inspector. I was at Cooper for about three-and-a-half years, and then I was a senior resident at Waterford for approximately four years, and then I came to the region for a few months as a project engineer and, as of January, became a branch chief.

So what I wanted to do real quickly this morning, because I know we're behind, is go over some of the regional initiatives that are basically above and beyond the oversight process as far as the procedures that inspectors use, try to talk about ways in which the region gains consistency throughout our inspection efforts, the way in which we share information relative to the inspection process, and the mechanisms by which we disseminate operating experience throughout the inspection staff.

The first thing that I would like to talk about is we have a program that's called STARS, where we review different inspector issues that are identified. And for those issues that really demonstrate a unique type of issue or an inspector that really had an interesting way in which he found a particular problem, we write up what's called a star, and that star is then talked about to the different inspectors. We have a board --

DR. SHACK: And STAR means what?

MR. HAY: Well, it's a star. It's like an inspector's star. It's --

DR. SHACK: So it's not an acronym that means something?

MR. HAY: No. It just means like, You are the star of the day. And so we have a board that's posted where we have all of these stars, and we put them on the website so that inspectors can go read them. And just to real quickly go over how I believe these are effectively used, going -- this process started back in 2002. Since then, we've written approximately 80 stars.

Going back to one here in 2002, I'm only bringing it up because I was involved in this one and I'm familiar with it, but it deals with at Waterford. We identified that they had a large section of ECCS piping that was voided, and Waterford then went to investigate that, and part of that led to other utilities finding the same problem, such as Palo Verde.

We wrote that up as a star. Like I said, we did find the same issue at Palo Verde. And then since then, we've written a star in 2006 where, out at Wolf Creek, the inspectors found voiding issues that were similar. We also have had problems that were similar in nature at Comanche Peak and Diablo Canyon.

So this is just one example where we not only find a problem but we share that with others so that they can go out to their sites and try to find similar problems. We had --

DR. SHACK: So you're communicating better than the industry appears to be doing.

MR. HAY: Well, this is just another way to do it, you know. There's OE that goes out. There's inspection reports that go out. And this is just one more way that we can share similar information and -- yeah. I won't say it's better, but it's --

DR. SHACK: Well, I mean they still have the voided piping?

MR. HAY: Correct. And that's unfortunate, but just that is true.

DR. WALLIS: Do you have a good handle of the consequences of having a voided pipeline? Do you have a good handle on what the consequences would be if the EECS came on with a voided pipeline?

MR. HAY: Well, there's a lot of -- well, first of all, the answer to your question is it's very dependent upon the plant that you're looking at. It's dependent upon the size of the void. It's dependent upon the flow rates of the systems.

DR. WALLIS: So presumably, you get transients, which give rise to high pressures or something? And --

MR. HAY: Right. I mean, well, there's big studies that go on for each one of these voiding issues.

DR. WALLIS: So someone does the engineering study?

MR. HAY: That's correct. And, you know --

DR. WALLIS: Do you do that here, or does it get done somewhere else?

MR. HAY: Well, I can give you a "for example," because it varies. Out at Palo Verde, when that voided piping was identified, they first of all tried to have it modeled at like a university using a very small-scale piping. They also had a contractor try to analyze the condition, and they weren't getting the exact same type of results. So they then went to a larger-scale model and ultimately went to a full-scale model. And it took them about --

DR. WALLIS: So it's a research project; it's not as if you know how to evaluate it right away?

MR. HAY: Well, right. I mean there's basic tools that we use, but each time you run into a voiding issue, those tools are somewhat limited, and it does take a lot of work to --

DR. WALLIS: So it might be some years before you know what the consequences might have been?

MR. HAY: Well, at Waterford, it took them only about two weeks, because they had a contractor who already had their piping system modeled, and they could easily do it. At Palo Verde, it took them about a year. So it's really dependent upon the specifics at each site. One other method of --

DR. WALLIS: I was just thinking that the punishment should fit the crime. But if you don't know what the crime is, then how do you decide what the punishment should be?

MR. HAY: Well, I mean at Palo Verde, we

determined that -- that issue came out to be yellow, which was, you know, definitely more important to safety than what we found at Waterford, where we found out that that issue was green. But again, the --

DR. WALLIS: So it's still a voided pipe, but the consequences are what determine whether it's yellow or green?

MR. HAY: Right. I mean just to give you an example, at Waterford, the voided condition was about 15 to 20 cubic feet. And at Palo Verde at all three units, their voided condition was around 125 cubic feet. And at Palo Verde, the flow rates were twice as high, which means that there was more propensity for that air to get sucked down to the suction of the pumps whereas at Waterford, that air would basically linger up at the high end of the suction piping and not be --

DR. WALLIS: Oh. So one consequence would be the pumps would not work then?

MR. HAY: Correct. And that was the issue at Palo Verde. And we determined the pumps could possibly --

DR. WALLIS: So it's not a pressure transient that you're worried about; the worst thing would be at the intake end and the voiding when the pump is sucking the air?

MR. HAY: Well, it all depends on where the air is at.

DR. WALLIS: Right.

MR. HAY: But yeah. If it's on the suction, it's typically the pumps. If it's on the discharge, it's typically a water hammer event.

DR. WALLIS: Right. So there's plenty of thermal hydraulics in this?

MR. HAY: Excuse me?

DR. WALLIS: I say there's plenty of thermal hydraulic consideration in these

MR. HAY: Oh, definitely.

DR. WALLIS: Okay.

MR. HAY: Definitely.

Moving on as quickly as I can, one other vehicle that we use is called a resident inspector counterpart meeting. Basically, twice a year for three days, we get the residents and the senior residents all together here in the region. Matter of fact, we work right here in this room. And we not only do training and things that are required, but, more importantly or just as important, we also share experiences.

And we do what are called site capsules. Where some important event or a very technical issue was identified, we'll have that resident or senior resident that was involved spend about 15 or 20 minutes and go over the details of that event or of that issue as a way to share those experiences.

We also do what's called an inspector newsletter, which most of you are, hopefully, familiar with. And it's not just a Region IV product. It's a product that all the regions contribute to, including headquarters. And, you know, for those of you that don't know what it is, it's -- basically, it looks like this, and it was developed really for the inspection staff, and it's another vehicle by which we share best practices and good inspector insights that have identified problems.

And just for example, this latest newsletter, again -- we have a write-up here that deals with Palo Verde and basically how they've gone from a plant that was thought of as having a pretty good safety record, but then it has changed over the past couple of years. And there's a write-up here on basically what has caused that change, what types of issues were identified and what kind of concerns did the NRC have, and what was the importance of all the different inspections that took place for the NRC to assess that. So that's in there.

There's also another write-up that deals with voided piping that was found at Comanche Peak. And this write-up even talks about, you know, These concerns were found at Palo Verde, and this licensee didn't use that OE very effectively to basically identify almost the exact same problem. So that's another vehicle that we use to share information.

MS. BANERJEE: How often are these issued?

MR. HAY: I'm sorry, ma'am?

MS. BANERJEE: How often are these issued?

MR. HAY: Oh.

MS. BANERJEE: These things.

MR. HAY: Yeah. The Stars are issued basically every time we do an inspection or every time we -- it's like a living document. So you could see a star come out any time. The newsletter -- that comes out quarterly.

MS. BANERJEE: Okay. Thank you.

MR. HAY: You're welcome.

We also every day have what we call our morning meeting, and that's at ten o'clock in the morning. We have DRP and DRS division directors typically there or their designees. We also have the branch chiefs for DRP and DRS. And the purpose of that meeting is to go over plant status at all of the sites and talk about issues that are happening that day or that week. And it helps us utilize the experience of that collective group.

DR. WALLIS: So you need that every morning?

MR. HAY: Every day, Monday through Friday. That's --

DR. WALLIS: Are there some days when there's nothing to say?

MR. HAY: Even those days. But those days rarely happen.

(General laughter.)

DR. WALLIS: A good day?

MR. HAY: Right. Some days are better than others. That's for sure.

One other thing that we do during --

MALE VOICE: And that is also participated in by the headquarters?

MR. HAY: That's correct.

One other thing that we do -- and we do more, but I'm bringing up one more thing. Every other Tuesday, we discuss focus areas and technical issues at each one of our sites. And basically, we put together like -- this is Palo Verde's. And at Palo Verde, we have a focus area of human performance and PI&R, which is reflective of the substantiative cross-cutting issues that they have.

But we also have focus areas that basically key people in on, What are the challenges that the NRC sees at that site. And I guess, just to give you some perspectives, we see challenges with respect to schedule pressures; that effects human errors. We see problems with the effectiveness of their performance improvement plan with respect to engineering activities.

And then we have technical issues that deal with specific component-type problems, whether it be pressurized reheater failures, a spray pump-type problem, spray pond-type problems Borg-Warner check valve problems. And I guess the reason I'm bringing this up is every other Tuesday, we talk about these things collectively and make sure that we understand, Do we have our resources applied where they need to be applied; do we still have a concern with this issue, or has it been resolved. It's just a good way for all of us to be on the same page with respect to all of our sites.

DR. MALLETT: Mike, why do we do this? Why do --

MR. HAY: That's a Davis-Besse "lessons learned" activity where we're basically -- and I don't know the specifics on what happened in that region, but this is our way to try to keep informed of problems that might seem small but problems that aren't fixed. We keep track of these technical issues, and they don't fall off of this until they're resolved or we've understood them.

And then the last thing I want to talk about is -- and we've already touched on this briefly, but it's our use of operator experience, operating experience. You know, the NRR does have a website where they post this sort of information, and our inspection staff does actively use it.

But I will say in addition to that source, headquarters' OE group does communicate with one of our regional technical support staff. And every day, he comes to that ten o'clock meeting and shares with us new OE that comes out. And that's where we decide, Do we need to get this out to the staff right away, or do we need to look at it internally more. And again, it's just a way for us to get that information out to the right people that can effectively use it.

That's really about all I wanted to say, with the exception of this here. This is another inspection tool that is really valuable especially for the new inspectors.

This little booklet is called, "The NRC Inspector Field Observation Best Practices." It was put together by a group of NRC folks back in November of 2005, and basically, it just goes through and talks about all of the different facets of being an inspector, things to look at, whether you're looking at fire protection issues, whether you're looking at gauges or whether you're looking at control room observations.

It really gives you just some fundamental things that we know are important for them to look at on a daily basis, because, you know, typically, when things are different than what they were in the past, there's a reason for why they're different, and they need to understand those reasons. And these tools really focus on those sorts of fundamentals.

DR. MALLETT: Mike, if I could add, that tool was created by the inspectors as a way of sharing their knowledge with the less experienced inspectors.

MALE VOICE: Could you pass it through so we can give it a look?

MR. HAY: Well, that's a good question. Can we get them a copy of that?

MR. GODY: Yeah. We'll try to. It's also available on the NRC web page.

MR. HAY: That's correct.

DR. SHACK: And could you locate it a little bit more precisely? I've had difficulties finding things on the NRC web page.

MR. GODY: Well, we'll get that for you.

MR. MAYNARD: And recognize we're not at our NRC offices full time.

MR. HAY: Right.

MR. MAYNARD: We're not there all the time.

MR. HAY: We'll try to get you a copy of that.

MR. MAYNARD: Okay. I've got a follow-up.

When you put STARS up there, I thought you were going to identify the best practices of the six plants in the Strategic Teaming Resource Sharing. But I understand now what you were saying.

It's time for a break. Let's take a break until 10:30, and then we will start back with a case. Thank you.

(Whereupon, a short recess was taken.)

MR. MAYNARD: Okay. I'd like to go ahead and call the meeting back to order. And I believe the next agenda topic is Reactor Oversight Process' Case Study Number Two.

Mr. Walker?

MR. WALKER: That's correct.

My name is Wayne Walker, and I'm going to present the Case Study Number Two. This -- I'm a senior reactor project engineer in Region IV here, and the plants that I have oversight of are Grand Gulf, Cooper and River Bend. The plant I'll be talking about today is Cooper. This is the case study that is going to be presented.

Just as a little background, Cooper was the first plant in our region that really, I guess you could say, fully exercised the reactor oversight process. The reactor oversight process went into effect in the late '90s/early 2000 time period, and Cooper actually got into this process fairly heavily in around the 2001 time period.

So first I'd like to go into how the oversight process increased on Cooper. In April of 2002, Cooper entered what we call the multiple/repetitive degraded cornerstone column of the action matrix because of a degraded emergency preparedness cornerstone that existed for more than four quarters.

What prompted this was that they had four white findings in emergency preparedness over a period of one year beginning with the fourth quarter of 2000 and going through the third quarter of 2001. These findings involved -- one, they had a failure to recognize a degraded core during an emergency exercise, and they failed to identify this failure during an emergency critique. They also did not take effective corrective actions for underlying performance deficiency and failing to recognize that degraded core.

Also, they did not make timely off-site notifications following an alert declaration as a result of a fire in a potential transformer. And then lastly, when they were staffing their emergency response facilities during that event, they didn't -- they weren't able to do it within the required time following the declaration of the alert. And that's the four issues that actually got them into the repetitive degraded cornerstone position.

DR. WALLIS: You said, Degraded core?

MR. WALKER: Degraded cornerstone.

MR. MAYNARD: Cornerstone.

DR. WALLIS: Okay. I'm trying to --

MR. MAYNARD: In fact, you said, "Core," but you probably meant, Cornerstone.

MR. WALKER: Well, one of the issues was that they failed to recognize a degraded core during an emergency exercise. That was one of the white findings.

DR. WALLIS: A degraded core?

MR. WALKER: Yes.

DR. WALLIS: What does that mean? A degraded core?

DR. CORRADINI: In simulation.

MR. MAYNARD: In simulation, meaning --

DR. WALLIS: It's only a simulation; it's not a real thing?

DR. CORRADINI: Right.

DR. WALLIS: Okay. Well, thank you. That's --

MR. WALKER: I'm sorry.

DR. BONACA: That's why we call it an exercise.

MR. WALKER: In the bullet I have up here, the 95001 -- if you're familiar with the reactor oversight process, the 0305 manual chapter. So basically what we did is -- we went down a path of -- our initial inspection involved a 95001, which was for some of the first issues. And once we did that inspection, we determined that we didn't feel the licensee had adequately addressed and with enough depth the corrective actions necessary to preclude this happening again.

So basically, we went out and did a 95002 inspection and came back with similar results. And then after they had these four findings and were in the repetitive degraded cornerstone, we went out and did a 95001 inspection.

The licensee put together a fairly extensive improvement -- they called it a strategic performance improvement plan -- that we inspected during 95003. And basically, from that inspection, we came back and said that we didn't feel that they had done an adequate job and had enough depth in that strategic plan to fully address all the corrective actions necessary.

And specifically, we pointed out -- there were six different areas we pointed out, some of them being the reliability of safety systems, personnel errors, implementation of the emergency plan, and quality of engineering, training and maintenance activities. It's pretty much across the board.

DR. BONACA: Now, the 95003 is an actual safety culture inspection. Right?

MR. WALKER: Well, it wasn't at this time. At this time, it -- that was before safety culture was even in the program.

DR. BONACA: Oh, I see.

MR. WALKER: And that's kind of what --

DR. BONACA: So this was before --

MR. WALKER: Right.

DR. BONACA: -- those changes were implemented?

MR. WALKER: Exactly.

DR. BONACA: Okay.

MR. WALKER: So the 95003 then was basically for the white findings they had and for being in the repetitive degraded cornerstone.

And what we did following that. Basically, we came back and -- they revised their strategic improvement plan, and we went out and looked at that again. And then in January of 2003, per the program, we went ahead and issued a confirmatory action letter to Cooper, which basically said, We see that you need improvement in these six areas, and we want you to follow through on your improvement plan.

There had been a long history with Cooper of having difficulty following through with improvement plans. And as an Agency, we felt like that was the proper thing to do, to issue the confirmatory action letter, as allowed by the 0305 process.

So they started down this road. Their strategic improvement plan had about 270 actions, and we determined that we would -- it looked like probably we could do about six quarterly inspections to try and close out these actions. So they went down a path of starting to do their corrective actions, and we went out and inspected on a quarterly basis their corrective actions.

One interesting thing that happened during this process was as we got about halfway through the confirmatory action letter closeout, they actually were -- they actually addressed all the issues in the EP area, the white findings in that area. And per the 0305 process, they could have reverted back to a level of oversight that would be under the regulatory response column, but -- and this is allowed by the program -- we asked for what we call a deviation from the program from the action matrix and got approval from NRR to go ahead and maintain our regulatory oversight at a level that was considering them to still be in a repetitive degraded cornerstone. And we continued that for another year-and-a-half.

Next slide. The -- basically, we considered that the ROP was used successfully. We did go ahead and -- like I said, we did six quarterly inspections. We looked at the -- examples of the areas we looked at were the human performance, equipment reliability, their corrective actions and their engineering programs. And we went ahead, and they made a request for us to close the CAL on September of 2004. And then in January of 2005, during a public meeting, we went ahead and closed the confirmatory action letter. And at that point in time, the second quarter of 2005, NPPD returned to the licensee response column of the action matrix.

I guess just a little background just to give you some idea on those six quarterly inspections. Typically, we had six to eight inspectors on those inspections, and we pretty much used a broad range of inspectors. We tried not to use the same inspectors on each inspection, but maybe one or two of the same inspectors just to get oversight of their program.

DR. WALLIS: When you held the public meeting, did you get input from the public? I mean did they get reassured by what you had done, for example?

MR. WALKER: Yeah, I believe so. We didn't -- there was not a lot of comments from the public.

DR. WALLIS: Not a lot of comment?

MR. WALKER: No. Early on in the process, the tendency to -- I should have mentioned this, too. After each quarterly inspection, we did a public exit, also, at the site, just -- not at the site, but just near the site, in Brownville, which is a couple miles from the site.

And typically, early on in the process, we had more public participation; as we progressed through, there was less. But there was typically probably 30 people at the meetings; maybe 40, mostly licensee individuals. Typically from the public, we might get five or six people. And also early on in the process, there was some discussion about the plant possibly shutting down. And at that point in time, there was a large amount of public interest.

Last slide, Brian?

I guess just for some conclusions on what we learned going through this process. This was, like I said, the initial plant in the region that we went through that, I would say, full exercised the reactor oversight process. One of the things we learned was that the CAL, the Confirmatory Action Letter, was a good tool for dealing with the licensee and, also, them being able to close out issues with us. It was a very methodical, organized, step-through process, and we were able to use that effectively.

I think also we learned that the ROP process is flexible. When you look at how we were able to issue the deviation memo to maintain oversight at a level that allowed us to still regulate them at a higher level than actually the ROP called for, I think that was effective, and it also was necessary.

And I guess what worked well. Like I said, I think that the CAL was a good idea. One of the things we did is -- we designated a single team leader for the quarterly inspections. And that gave continuity to our inspections and to our efforts and allowed us to maintain that throughout the process.

If you look at it, the process took about almost three years to really close out the CAL. So it was a fairly long process. And also, by having a designated team leader, it allowed him to be able to train the individuals that were going on the inspections and give them a history of what had gone before, what the strategic improvement plan consisted of -- it was a huge document -- and allowed him to step those inspectors through, you know, how that was organized and what we were going to be closing out and what we were looking at during the inspections and what had gone before.

And also, I guess what maybe did not work so well is -- it just kind of gives you an idea that this process can get very drawn out. And it is very much based on the licensee being able to close issues out, and it does take a lot of time for us to go out and inspect, and it's very resource-intensive.

So in a region of approximately 160 people, that's a lot of resource to take away every quarter to go do inspections in addition to the other inspections you're doing as a region. So we did draw on other regions some, but mainly we did it with our own region personnel.

DR. BONACA: I have a question. Was -- you said that the procedures that you used, 95001, -2 and -3, were before the changes for safety cultures were implemented. The question I have is, How different would have been what you went through and the process and the results if you had used the new procedures where the safety culture changes are implemented and in effect?

MR. WALKER: Right. I anticipated this question, and I don't have a good answer for you. I don't know if Linda might --

Linda?

Linda does a lot in the safety culture. I thought I might let her try and answer that question.

DR. BONACA: Okay.

MS. SMITH: The latest safety culture initiative really added on opportunities for the licensee to do their own safety culture assessments and, also, for us to assess that effort. And so the first part's still the same. So the things that he worked under, that program with the CAL, that's all still in place and could be used that way. But they added the safety culture assessments to the 95002 and 95003, and I'll talk a little bit more about that in my presentation.

DR. BONACA: Okay. Thank you.

MR. WALKER: I think you were --

DR. ABDEL-KAHLIK: What is the cost to the licensee of maintaining a higher level of inspection than what's called for?

MR. WALKER: Well, we charge our hours based on inspection hours. So I don't have the exact numbers. I'm sure we could probably get those. But it's a very high cost if you consider we did six quarterly inspections, there were six individuals to eight individuals on each one of those inspections, and they were week-long inspections. Plus there was some preparation, a week, and documentation, a week, for each one of those.

So a minimum of about 18 weeks of inspection effort in addition to what we would normally do. I mean that's above and beyond the baseline program.

MR. MAYNARD: These have significant impact on both the licensee and the NRC.

MR. WALKER: Correct.

MR. MAYNARD: It takes resources away from the NRC that may otherwise be used for other things. And for the licensee, not only the hours are paid for, but, you know, they have an equal or just as much effort within their own staff of getting things ready for these, and stuff. So it's an impact for both.

MR. WALKER: Yeah. It's a huge burden on the licensee to prepare, also. That's correct.

MR. WERNER: The current 95003 has approximately 2,500 hours of what we call direct inspection activities allocated.

MR. MAYNARD: And you need to identify yourself, too.

MR. WERNER: I'm sorry. I'm Greg Werner; I'm a senior project engineer and have oversight for Palo Verde. I'm assistant team leader for the upcoming 95003 at Palo Verde.

The current 95003 procedure has approximately 2,500 hours of baseline inspection. Of that, NRC added approximately 460 hours of baseline inspection associated with the safety culture portion.

So we're going to have four dedicated inspectors looking at safety culture aspect impact on plant performance of Palo Verde. So that -- again, 2,500 hours is probably double that for preparation and documentation. So probably a total of around 5,000 hours of inspection effort will be expended just alone on the initial 95003 inspection at Palo Verde.

DR. BONACA: So on 95001, you're looking at a narrow area typically of repeated events in the same type, and then you open it up to 95003, where you're saying, We are concerned about your safety culture, which is much broader, and we're going to look at it. How do you get to that step wise? I mean is the region involved in also make the decision that you have to go from 95001 to 95003?

MR. WALKER: Yeah. The way we did that -- I mean I don't -- Greg can talk about Palo Verde.

MR. WERNER: Go ahead.

MR. WALKER: But at Cooper, the way it worked was that the 95001 -- once we came back from that inspection, we didn't feel that they had done effective corrective action.

DR. BONACA: Okay.

MR. WALKER: So that caused us to go to -- and then on top of it, they had additional issues that came about during that time period. So then we went to 95002, and then we still didn't think they had done adequate corrective action. So then you get to 95003, and it pretty much -- at this point in time in the process, that broadened it. And then we said, Yeah, there's a whole programmatic.

DR. BONACA: So the licensee understands well why you're going from --

MR. WALKER: Yeah. It's very clear -- it's clear to them, I believe, yes.

DR. BONACA: All right.

MR. WERNER: Just to expand on what Wayne was saying, in Manual Chapter 0305, if you look at the action matrix, it's very well laid out as far as what violations or what findings drive them into the next column. So again, as we've said before, it's a graded approach to performance.

MR. WALKER: Yes.

MR. WERNER: So as their performance declines, we'll put more NRC resources as far as inspections. Of course the 95003 then looks at all essentially site processes to see what caused the degradation in performance. We're not just looking for equipment issues; we're looking much broader than equipment issues.

MS. SMITH: But it circles back around to the --

MR. MAYNARD: You need to talk into the microphone. I'm sorry.

MS. SMITH: The action matrix that he just passed out -- that was in place while he was doing the

Cooper effort. But the evaluations of the safety culture and the ability to require the licensee to do a safety culture assessment -- that's something that happened later. And before -- but they're beginning to do it now for the first time in the Palo Verde area.

MR. WERNER: Yes.

MR. GODY: For the record, that was Linda Smith.

MR. CHAMBERLAIN: This is Dwight Chamberlain. I just wanted to comment on your question about, you know, if we had applied the new process to Cooper. I think time's going to tell. We're going to apply this new process for the first time at Palo Verde. So we're going to do just like we did with Cooper, and we'll have lessons learned from that, and we'll probably need to make adjustments to the program after that. So I think time's going to tell how well it's going to work at Palo Verde.

DR. BONACA: Okay.

MR. MAYNARD: Did you run into much problem in trying to determine, What does it take to close out -- I mean the performance doesn't have to be perfect. So there are going to be some issues still in underlying -- what does it take -- how do you know when you reach a point when it can be closed? I'm sure that was a challenge.

MR. WALKER: That's a great point. I mean we really -- we struggled with that. Obviously, you can imagine the licensee was putting a lot of pressure on us to say, Hey, we've done enough, you know; when's enough. And we came to the consensus that it was enough, you know. And that's -- we made that decision. But yeah, it's a subjective call.

I mean we look at the -- obviously, we ensured that all of the action items were closed out. That was one of the things we looked at. And then one of the -- when they first came to us, that was one of the things -- we didn't feel they had adequately closed some of those action items. And we said, Hey, you know, you need to go back and relook at a few of these areas. And they did that. And that eventually led to a closure.

MR. CHAMBERLAIN: I mean I thought it was interesting that we did close out the CAL with substantiative cross-cutting issues still existing. Right? And we acknowledged that they still had performance issues, but we took them out of the increased oversight except for those substantiative cross-cutting issues.

MR. WALKER: That's right. That's correct.

MALE VOICE: Okay. If there are no more questions, let's go ahead and move on to the next topic here, Reactor Oversight Process Case Study Number Three, with Mr. Warnick.

Thank you very much.

MR. WALKER: Thank you.

MR. WARNICK: Thank you. My name is Greg Warnick; I'm the senior resident at Palo Verde. I was actually assigned there in 2000 as the resident inspector, and then in December 2004, I was promoted to the senior resident inspector. So I've been there a number of years.

I'd like to talk a little bit about just some of their historical performance. Like I said, I've been there a number of years. And I've seen them progress from one of the industry leaders to the point where they are right now.

MR. MAYNARD: Progress may not be the right word.

MR. WARNICK: Decline.

I'd like to talk a little bit about their current performance and our current assessment and then some of the value added that we've had through the revised oversight process.

Palo Verde has had a good reputation as one of the industry leaders in past years. In fact, they talked often about their ten years of excellence, and that has celebrated in part their ten years as an INPO 1 performer, as well as numerous industry records that they had set over that performance period.

Plant performance for 2003. It was within the licensee response column of the action matrix. And I see we were just handed a copy of that action matrix. We're going to talk a little bit, as I talk about Palo Verde performance, how they transitioned from the licensee response column to where they currently are, in the repetitive degraded cornerstone column.

DR. CORRADINI: Licensee response, just to get my colors, that's green?

MR. WARNICK: Well, it's really not a color associated with it. What it means is the level of effort and regulatory oversight is under the basic baseline inspection program. So we implement the baseline inspection, the licensee is a good performer, and they can correct their problems, and we don't have issues associated with that.

As we identify findings, as well, illustrated here with the Palo Verde case study, depending on the finding and the significance of it and, you know, what cornerstone it's related to, they can transition to have a higher level of regulatory oversight.

NRC oversight at Palo Verde has identified a declining licensee performance starting in 2004. A large number of event-driven plant trips and power reductions to deal with emergent issues occurred; many of the issues involved latent organizational and programmatic issues and degraded plant equipment. The number of inspection findings increased from five in 2003 to over fifty in 2004.

The most safety-significant issue began to develop in mid-2004 when the resident inspectors at Waterford identified an issue involving a section of containment sump ECCS piping that was void of water during power operations. In fact, Mike Hay, who spoke to you earlier -- he was the senior resident at that time who identified that. They identified that that voiding water could have a potential impact to that system since it hadn't been previously analyzed or tested.

When Waterford contacted the other combustion engineering plants in the industry to alert them of a potential design problem, that word reached Palo Verde. Analysis of the issue revealed that the condition presented a significant challenge to the emergency core cooling system of Palo Verde, and, consequently, we performed a special inspection. That special inspection did result in findings.

In April 2005, we forwarded a letter concerning the final significance determination of a yellow inspection finding in the mitigating systems cornerstone.

That finding involved a significant section of piping -- Mike Hay, in fact, told you what size that void was -- at the sump suction for the suction of the ECCS pumps. It was identified that that void of water actually existed since 1992. So it was there for many -- a large number of years, all the way until 2004, when it was identified.

The voided section of piping had the potential to prevent the fulfillment of safety function following the loss-of-coolant accident. In May 2005 --

DR. WALLIS: When you say it had the potential. Did it -- how serious was this potential?

MR. WARNICK: Well, it was a -- yellow significance is what we determined it to be.

DR. WALLIS: Was there some sort of an analysis performed to show if the pump would work or not?

MR. WARNICK: Yes. There was extensive analysis. I heard Mike Hay talk a little bit about what the licensee did. They did some small-scale mock-ups all the way until they did a full-scale mock-up. We evaluated that through our significance determination process. We held enforcement conferences. And together with our probable risk assessment, we determined that it was of yellow significance.

DR. CORRADINI: So if you could just -- if it's not too much time off your schedule. So since 1992, what was -- there was a blockage or there was a partition? I'm not exactly sure what --

DR. WALLIS: There was air in the intake pipe, right, to the sump pump?

MR. WARNICK: Yeah. Actually, the way this developed is Palo Verde -- you see discussed here a 50.59 violation at the top. That was associated with the licensee consciously making a change to their procedure, without prior notification to the NRC, to maintain a section of pipe dry. And that --

DR. WALLIS: Oh. So they consciously did it?

MR. WARNICK: That's right. And the reason was every 18 months, they have to cycle these valves for in-service testing and, as they do that, the section of water that was at the suction of the pump just at the containment penetration would dump back into the containment sump itself, and that would create a housekeeping issue where they'd have to go in every outage and clean it all up. And to eliminate that hassle and that housekeeping problem, they said, Well, why don't we just keep it dry.

They didn't, obviously, do a very good analysis of that decision, partly in which we identified the Severity Level III 50.59 violation. And since that point in 1992, they consciously maintained it void of water for a number of years.

DR. CORRADINI: So just one last question, because -- it has to do with geometry details. So during an accident situation, it was not concluded that that would refill naturally itself by essentially flow-down and other ECCS discharge into the sump?

MR. WARNICK: That's partly what they believed. They believed as an accident occurred, water would drain into the sump and then slowly fill up that section of piping. However, once we identified the issue in 2004 and they started to do the analyses and the mock-up testing, it became apparent that that wasn't the case.

DR. CORRADINI: So it would have created essentially a void space that would not have been filled?

MR. WARNICK: That's right. And as Mike Hay talked about, that void was shown to have a probability of reaching the suction of the pumps and causing a safety-significant issue.

DR. SHACK: Now, did the NRC know that that was voided, and you only became concerned after the Waterford? Or how was it discovered?

MR. WARNICK: It was discovered through Waterford asking about that situation. I personally was not aware that it was maintained dry. That was news to me as that issue came up. A lot of the people on site knew it was voided, but, because it had been that way for so many years, they understood, as you suggested, that, Hey, the water would fill it up, and it's not going to be an issue.

DR. CORRADINI: So if staff knew, you probably would have come to the same potential judgment without testing? Is that kind of what I just heard?

MR. WARNICK: I can't say that. If I just --

DR. CORRADINI: Not knowing any better, I guess I would have immediately assumed that unless there's some peculiarity about the geometry and how it fills.

MR. WARNICK: Yeah. That's why Mike was talking about some plants -- you know, it depends on the design and the arrangement of the piping, the angle of the piping and so forth -- how that's going to happen. And that was the assumption the licensee took as they made those changes to their procedure.

DR. WALLIS: Now, does that mean that they didn't run the pump for 12 years?

MR. WARNICK: Well, they did. But typically --

DR. WALLIS: Well, what did they -- how did they run it if there was air in the line?

MR. WARNICK: Yeah. This is talking about the containment sump suction --

DR. WALLIS: Yes.

MR. WARNICK: -- which is taking the suction on the sump as it fills up with reactor coolant from a loss-of-coolant accident.

DR. WALLIS: Right.

MR. WARNICK: When they run the pump, their suction source is typically from their refueling source.

DR. WALLIS: So they bring the pump water from somewhere else?

MR. WARNICK: That's right.

DR. CORRADINI: There's a valve between that and the pump, and they run it on recirc?

MR. WARNICK: That's right. That's where the initial supply of water comes from in a loss-of-coolant accident. And then eventually when the containment fills up, there's enough water to take the suction --

DR. ABDEL-KAHLIK: Is there a bigger issue beyond, you know, the voiding of a section of pipe which relates perhaps to the adequacy of analyses performed by licensees in support of 50.59 modifications?

MR. WARNICK: Yeah. And that was the nature of the violation here. And that's a good point for me to continue on through this, and I can illustrate some of that.

We did give a violation for Severity Level III. And that required the licensee to take actions. And in fact, they recognized that there were some weaknesses in their approach to those types of analyses and the rigor that goes into them.

DR. ABDEL-KAHLIK: But not just that particular licensee, but in general, how would you sort of confirm the adequacy of analyses performed in support of 50.59 modifications?

MR. WARNICK: Well, we confirm that through our day-to-day inspection activities. Part of our baseline inspection process is -- we look at temporary modifications, permanent modifications and plant changes. And as part of those reviews, we look at the adequacy of the 50.59 evaluation that takes place. And we as the inspectors make those determinations as to whether or not their program is sound to look at those kinds of things.

MR. MAYNARD: There are also periodic team inspections that are very focused that will take a slice and do a very serious -- and take a look at the 50.59 and other evaluations --

MR. WARNICK: Absolutely. And those --

MR. MAYNARD: -- in those inspections, too.

MR. WARNICK: And those are part of our baseline inspections that are performed from our engineering branches in the region. And they look at those things in detail.

So as we talked about briefly there, we did identify that they had that issue at Palo Verde, and that did result in the yellow finding, which put them into the degraded cornerstone column. And being in that column requires a 95002 inspection. That inspection was first done in December 2005.

And that inspection team concluded that not all the corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed, and that the reviews were not established to ensure the corrective actions were effective in improving performance. Consequently, we left that yellow finding open pending a completion of a follow-up 95002 inspection.

Now, as I mentioned before, there was a Severity Level III violation of 50.59. That team did conclude that the actions were adequate there to correct the deficiencies that they had in the adequacy of their evaluations for their plant changes. They made a number of changes to their overall process to include that.

The declining performance trend was not corrected in 2005; that was mainly due to the licensee's symptom-based and narrowly focused corrective actions. Palo Verde did develop and began implementing a performance improvement plan in 2005, and they determined that they needed to develop and implement a plan based on the downward trend that began in 2003. And that's relative to the sustained high performance levels that they had in previous years.

They themselves determined through that performance improvement plan and that analysis that it appears that that trend may have come up due to the realignment of key site leadership that caused them to be more focused on day-to-day matters and less focused on strategic planning, standards and accountability.

Management also determined that two events in 2004 -- there was a three-unit loss of off-site power where all three units tripped offline, and this emergency core cooling voiding issue -- revealed issues with regard to various Palo Verde programs and processes that needed improvement.

Additionally, they needed to address the large number of NRC inspection findings that we were identifying, as well as NRC's and INPO's assessments of their declining performance. At that time period, they were degraded or -- I don't know the exact term, but they were categorized to an INPO III performance plant through their INPO evaluation that took place.

DR. APOSTOLAKIS: These inspection findings were green? When you say, High number if inspection findings --

MR. WARNICK: Yes. I mentioned before that we identified over 50 findings in 2004, one of which was yellow, the finding that we had. The others were green.

DR. APOSTOLAKIS: All right.

MR. WARNICK: So that's why they went to the degraded cornerstone column. In 2006, we identified over 40 findings, so, again, a high number of findings. But those were all green. And in 2007, as I get to it, we identified an additional finding along with numerous others, but one of more-than-green significance. And that was white. And I'll talk about that in a moment.

DR. APOSTOLAKIS: So this is really a matter of judgment? I mean at which point do you decide about the number of --

MR. WARNICK: Well, actually, the revised oversight process is very prescribed. We have the action matrix there in front of you -- and our 0305 process as we assess the performance of a plant. Depending on the significance of a finding, which we evaluate through our significance determination process -- depending on that finding and the cornerstone that it impacts, they would go, prescribed by our process, into a column of the action matrix which would require a level of inspection after, such as in this case, a 95002.

DR. APOSTOLAKIS: No, not as prescribed. I understand that. But what is the high number of inspection findings that would lead you to the conclusion that there is a cross-cutting issue? That's the judgment of the NRC inspectors, is it not?

MR. WARNICK: Oh. Well, once again, it's in our manual chapter 0305. And in fact, that high number of inspection findings in 2004, as we saw in the last slide here -- well, let me take it back.

DR. APOSTOLAKIS: There you go.

MR. WARNICK: It was two slides ago. Anyway, we did identify in the fourth quarter of 2004 that there were substantive cross-cutting issues in both human performance and problem identification and resolution. And that conclusion came from those inspection findings that we've had.

As we looked at the criterion in manual chapter 0305, the criterion was satisfied. And because of that, we issued in our assessment letters substantive cross-cutting issues in human performance and PIR.

DR. APOSTOLAKIS: I guess it's not very clear. I mean there are green. You have 30 green. Right?

MR. WARNICK: Okay.

DR. APOSTOLAKIS: A high number of allegations, 30 green. If there were ten, would you still conclude that there is a cross-cutting issue? If there were five? Is it the number that determines what it is, or is it -- I mean if it's judgment, it's judgment.

MR. MAYNARD: First of all, the high number of allegations, greater than 30 -- those aren't findings.

DR. APOSTOLAKIS: No.

MR. WARNICK: That's correct.

DR. APOSTOLAKIS: I'm talking about the findings.

MR. WARNICK: Okay.

DR. APOSTOLAKIS: If you have ten or fifteen --

MR. WARNICK: There's --

DR. APOSTOLAKIS: Is it just the number, or is there something else?

MR. WARNICK: I hear you.

MALE VOICE: There's three criteria to meet --

DR. APOSTOLAKIS: Oh. The three you mentioned earlier?

MR. WARNICK: Yeah, that's right.

DR. APOSTOLAKIS: Could you repeat those?

MR. WARNICK: Sure.

DR. APOSTOLAKIS: The third one was very important. Start with the third one.

MR. WARNICK: The -- start with the third one?

DR. APOSTOLAKIS: Yes.

MR. WARNICK: Okay. The third one is: The Agency has a concern with the licensee scope of efforts or progress in addressing cross-cutting area performance deficiencies.

DR. APOSTOLAKIS: Okay. And that is a judgment on the part of the Agency?

MR. WARNICK: Yeah. That piece is a judgment.

DR. APOSTOLAKIS: And it's not based strictly on the number of greens? I mean --

MR. WARNICK: Well, Criterion 1 is multiple green or safety-significant inspection findings in the assessment period with documented aspects in human performance. So it is the number of green if they have an aspect of human performance.

And then the next one has to do with the cornerstone that it's impacting. If those are there and then the third criterion we apply in a judgment -- are we concerned that they're not fixing this -- that would meet the criteria, and, per our guidance, we would issue a substantive cross-cutting issue. Is that clear?

DR. APOSTOLAKIS: Yes. Thank you.

MR. WARNICK: Okay.

DR. MALLETT: Let me add something. This time, in this cycle of reviews that we just finished, we had in particular a long discussion on one of the licensees that had a number of findings tagged with cross-cutting aspects. I don't remember the number, but it met the first criterion.

They all had a common theme, but we debated for quite some time; we just didn't think there was a concern on the part of the Agency related to their performance, and they really hadn't had any impacts on the plant performance from that. At Palo Verde, there were impacts on the plant that you'll see when Greg goes on here that were occurring.

MR. WARNICK: Thanks, Bruce.

DR. APOSTOLAKIS: Yeah. I don't remember right now, but would you remind me again the -- you said the mid-cycle inspection. The baseline inspection? How often is that done?

MR. WARNICK: The baseline inspection is done every day.

DR. APOSTOLAKIS: Every day?

MR. WARNICK: And that's done by us, resident inspectors, as well as a few, as was mentioned here, engineering inspections, fire protection inspections, which are done by our supporting cast in DRP and DRS in the region.

DR. APOSTOLAKIS: And the mid-cycle?

MR. WARNICK: The mid-cycle? What he's

referring to is: Twice a year, we do an assessment of our ongoing inspection activities and our oversight.

DR. APOSTOLAKIS: I see.

MR. WARNICK: Now, there's a --

MR. MAYNARD: That's not an additional inspection. That's a gathering of all the information from inspectors.

MR. WARNICK: That's exactly right.

DR. APOSTOLAKIS: Oh. Okay.

MR. WARNICK: And Bruce is referring to our mid-cycle, which actually just finished up within the last week or so, where we gathered the results from the last six months or so of inspection, as well as what we learned from before that, and we evaluated, Are we looking at the right things; do we need to do things differently, where do we need to go from here.

DR. APOSTOLAKIS: Okay. Thank you.

MR. WARNICK: Okay.

All right. We're to 2006 now. They're -- the licensee at Palo Verde is in the degraded cornerstone column, and that was based on the yellow finding that was carried forth from the fourth quarter of 2004. Palo Verde -- they did present their performance improvement plan during a March 2006 public meeting. It appeared to be a decent plan; however, they continued to struggle with the implementation phase due to the high number of issues and events that redirected their attention.

My observation at the site was that as soon as a new emergent issue or event would pop up, which was actually very frequently at Palo Verde as you look at their power history -- a lot of emergent down-powers, tech spec shutdowns, plant trips and things like that -- we observed that as soon as those things came up, they'd put their plan back up on the shelf and kind of go back to their old, comfortable way of doing things.

On numerous occasions, we have had to prompt Palo Verde personnel to perform evaluations and provide additional supporting technical bases for operability decisions associated with plant issues and problems. The lack of timely and thorough evaluations have resulted in fixing symptoms instead of the actual causes, the existence of latent issues that manifest themselves in plant events and inoperable equipment, inadequate and untimely operability determinations per equipment problems, and accepting incomplete or unvalidated information to support operational decisions.

I was the team leader for the follow-up 95002 inspection that we performed. We completed that in July 2006. This inspection was performed just after the identification of a potentially-safety-significant issue related to spray chemistry.

And that, by the way, is Palo Verde's heat sink.

It was interesting because while my team was reviewing the corrective actions taken to correct the performance deficiencies associated with the yellow findings, we actually saw many of the same performance deficiencies in their response to the spray pond chemistry issue.

And it was good for us, my team, to see real time, to add to the observations that I see through my baseline inspection process, that their actions have been inadequate, since they were making the same mistakes in their responses to the spray pond chemistry issues as they had with the voided piping finding, the yellow finding.

DR. CORRADINI: Can you help us there? What do you mean or can you give a little more detail on the spray pond chemistry issue and their response to it that caused you to pause?

MR. WARNICK: Certainly. Through our baseline inspections and some self-revealing events, it became evident that heat exchangers that are cooled by the spray pond water, specifically the diesel inner-cooling heat exchanger, was -- the performance of them was degraded to the point that as they started to take off the end valves and inspect, they call kind of a gooey substance in there, and it was coating all of the tubes, degrading heat transfer.

As they started to pull the string and go back through history, we actually sent a special inspection team out to look at that and identified that there was a long-standing issue with how they control their chemistry, to the point where they weren't coordinated properly and caused this gooey substance to appear in all of the heat exchangers, shutdown cooling heat exchangers, and so forth.

Their response -- what I'm talking about as to why we left the yellow finding open -- was because their ability to have a questioning attitude, give technical rigor in evaluating issues, as well as the programmatic concerns that we had with their operability determination process -- we felt those -- the corrective actions associated with this areas were inadequate.

So the same types of behaviors that were necessary to deal with the spray pond chemistry issues -- again, it was a long-standing problem that had revealed itself only through equipment degradation. Their response once that degradation became apparent was untimely, and their evaluations were shortsighted. And many times, we, the NRC, had to step in and ask them for more information related to an evaluation to give a good basis for why -- operability issues.

While the licensee developed corrective actions in late 2005 to address the performance issues, they continued to struggle with effective implementation in 2006. And as I mentioned, I was the team leader for that inspection. And I recommended that we leave the yellow finding open because they hadn't fixed their problems and corrective actions were lacking in those areas I discussed, as well as that their effectiveness measures were inadequate in the ways that they determined that continued performance was sustained.

Current performance I talked about earlier, answering the question where -- in late 2005, an issue came up with the Train A diesel generator in Unit 3, where there were some failures. A special inspection was performed, and it was identified that there was a white finding associated with the performance deficiencies for that failure.

In February 2007, we did issue a white finding in the mitigating systems cornerstone. In the annual assessment letter that followed that up, we placed Palo Verde Unit 3 in the repetitive degraded cornerstone column of the action matrix.

And additionally -- I told you that we

continued to find a high number of findings. For three years in a row, Palo Verde has had substantive cross-cutting issues in the areas of human performance and problem identification and resolution. Over the same time frame, safety-related equipment failures and degraded plant conditions continued to be identified by self-revealing events, as well as by the NRC staff.

DR. BONACA: The question I have is that -- some of these issues are long-standing issues, you know -- for example, lack of 50.59 for the sump piping, or the heat exchangers' chemistry. And it seems that, you know, the finding on the piping from the Waterford event began to unravel just because we began to look more thoroughly. And do you have any observation of that? I mean how much of this was already there before, when they were still rated an INPO 1, I mean, and that led them to complacency in a way, because they were a One?

MR. WARNICK: That's well stated. That's -- one of the observations that we've had is that they got into a state of complacency. They didn't have any equipment challenges, and they were able -- even though they've looked back and identified and we ourselves have looked back at how they arrived here, some latent equipment issues and latent plant conditions were out there.

Their programs and processes had been altered to the point where they became ineffective to certain extents -- as well as complacency set in. They met some challenges in 2004. The first big challenge was the loss of off-site power, where they had a three-unit trip. And we had an augmented inspection team go in there -- and in fact, Tony Gody was the team lead for that -- and identify numerous issues. And that was really the beginnings of us starting to be able to look closer to kind of uncover some of these long-standing issues that they had.

And as I'll illustrate here in the next slide, in many of these cases, we were ahead of the licensee in identifying those deficiencies. And I'll continue on in a minute about those.

DR. SHACK: Well, the other thing you said was that even when they found them, their corrections were not -- I mean it's one thing to have a long-standing issue, but you'd think that when you'd find it, you'd put it to bed.

MR. WARNICK: That's right.

DR. SHACK: And if you don't, then there really is a problem there.

MR. WARNICK: That's right. And they've struggled with that. And that has been our ongoing assessment and one of the main reasons for why they have a substantive cross-cutting issue in problem identification and resolution that has been going on three years now.

Okay. I'd like to talk a little bit here about value added through the revised oversight process, which is really what I wanted to illustrate with this case study.

These 2004 NRC inspectors were able to identify these key issues ahead of the licensee. On many of the issues when first identified for the licensee, they argued that we were wrong and that the opposite was true. They tried to remind us what a great industry performer they were and that what we were identifying just couldn't be true. They were actually in a state of denial.

For example, in late 2004, when I started discussing the potential substantive cross-cutting issue in the area of human performance, Palo Verde presented me with their site metric and showed me that site metric and argued that we were wrong in our assessment, because they couldn't have a finding trend in the substantive cross-cutting issue of human performance because their site metric actually showed that their trend was improving and that things were getting better from a human performance standard.

We documented the cross-cutting issue, despite what the licensee believed, because we satisfied the three criteria that we talked about before. Since it was a documented issue, the licensee then initiated an investigation to understand the issue.

DR. WALLIS: So I was wondering if their declining performance wasn't because your performance improved in finding things, rather than that they declined.

MR. WARNICK: Well, I mentioned that in 2004 --

DR. WALLIS: Because they thought they were just as good as before.

MR. WARNICK: That's right. They felt that they were a victim of bad luck. And in fact, the three-unit loss of off-site power had to do with a natural occurrence that happened many miles away and caused a transient on the grid. What that did, though, was uncover some programmatic and process problems within their organization and how they deal with corrective action processes, processes with their emergency planning, implementation, and so forth.

We had a number of findings that came out of that, as well as other issues. And as soon as we had the new information necessary to make the assessment with the 0305 criterion, we used that tool that we have, our guidance document, and issued the human performance substantive cross-cutting issue. Still the licensee didn't believe it until many months later, when they themselves did a screening analysis and reached the same conclusions we did.

I'd just like to give one illustration of a finding that I was involved with identifying that I think illustrates this very well. And I feel that this is one of the most important inspection findings that I've identified at Palo Verde, and it's an outstanding example of where the NRC has added value to the revised oversight process. It's a culmination of numerous isolated findings that I've identified over the past years that all had overtones of a production-over-safety mentality.

The development of my conclusions associated with the poor Palo Verde safety culture started with my identification of a poor decision-making process, as exhibited by the licensee when they discarded unsatisfactory results from an auxiliary feed water pump discharge check valve test to be able to continue with load escalation to come out of an outage.

This was followed by multiple examples of a failure to follow the operability determination process and culminated with several self-revealing and licensee-identified findings over the 2005 to 2006 time frame for operator human performance error, when my follow-up and the direction that I provided to my inspectors revealed that the errors were driven by a self-imposed schedule pressure.

I oversaw the performance of the trend review to evaluate the multiple examples that I was involved in identifying to conclude that the culture within Palo Verde's operations department was such that the standards of expectations were relaxed during periods of high activity, as well as when faced with technical specification time-driven operability decisions, to the extent that safety-significant errors and non-conservative decisions were being made.

I received considerable push-back on this conclusion from licensee management. However, it was apparent to me and the region that the licensee was not taking appropriate actions to correct the condition, because they failed to recognize it. Eventually, like other issues that we have identified, the licensee's own root-cause investigation reached the same conclusion that we had reached months later or -- months earlier that we had reached.

So my identification of the issues drove the licensee to approach their investigation and correction of the significant and human performance weaknesses in a different manner to improve the operator's performance to a level needed to safely operate the plant under all conditions.

This discussion illustrates the importance of how our inspection efforts in the revised oversight process are used to assess licensee performance and take additional actions when a finding of performance is recognized. An important lesson that the Palo Verde study illustrates is that licensee performance is a dynamic condition that continuously needs to be assessed using the tools available to us through the revised oversight process.

Any questions?

DR. APOSTOLAKIS: Yeah. The yellow finding is still yellow?

MR. WARNICK: That's correct.

DR. APOSTOLAKIS: Since 2004?

MR. WARNICK: Since the fourth quarter of 2004. And that yellow finding will also be addressed through the 95003 inspection team coming up.

DR. APOSTOLAKIS: So can it be there forever? I mean what can you do if they don't fix it?

MR. WARNICK: Well, let me state that Palo Verde is making significant strides in changing their performance.

DR. APOSTOLAKIS: But let's say they don't want to do it. Does the ROP say -- at some point, you know, you decide enough is enough and you take more severe action?

MR. WARNICK: Well, we'll continue the 95003 process. And if their performance continues to degrade and doesn't turn, then, certainly -- I think it's the 0350 process -- we can step in and, with management decisions, we can evaluate during our assessment periods where we need to go from there if the licensee isn't changing their level of performance.

DR. APOSTOLAKIS: Is the --

DR. MALLETT: Let me add something, though. What we found in this example was that a licensee -- when they have a yellow finding from a risk significance perspective, they may close out the technical piece of this. They closed that out early on in the process by filling the pipe, obviously. But the programmatic causes of that, like the 50.59 reviews and so forth -- that's what they hadn't closed out.

So what we said -- this last year when we reviewed this oversight program in our annual review, the Agency's action review meeting, we said there's something wrong with a licensee that stays in this area forever and doesn't fix these programmatic issue. So we -- speaking from an old health physicist, you crank up the gain a little bit on the potentiometer, and you -- of course, the new people don't talk that way, but, anyway, I crank up the gain.

And so what we decided we're going to do is change the process to raise the level of effort from the NRC's standpoint to where we will have the regional administrator meet with the licensee, have them develop a performance improvement program and raise that to that level. If they don't fix those issues, then we'll have to have -- make a decision like, in Palo Verde's case, do they -- where do we leave them. Do we leave them in this column, or do we do something more.

So I think we are making changes to crank up that gain, so to speak, to take more actions. But right now, they've been in a form of, Your plans at the site have not fixed this problem; what are you doing to fix it.

One of the things you saw this year, though, is they came in to me with the commissioners this year. That was one of the changes that we put in the program to say, Well, when you go into Column Four, then you're going to meet with the Commission, as well, and explain why you're not fixing this thing.

So I wanted to add one more thing that Greg doesn't have in any of his slides. The key to any inspection program, to me, are the inspectors, whether it be the residents or the regional inspectors. And early on, long before we put cross-cutting issues in place, they were saying, There are problems at this site in how they're performing. And they started showing up about a year after they told us this in performance issues at the plant.

So those people look for early indicators in the process. That's why I said this retention and recruitment of these skills is so important, because Greg and others actually picked up on these issues, I would say, at least a year before the process picked up on them.

DR. CORRADINI: Could I ask just one thing? So I guess, to follow up George's question, so maybe you're not allowed to say this because of the procedures. And I don't understand them. But you said you're going into what in the fall, a 95003?

MR. WARNICK: Well, that's required by the action matrix --

DR. CORRADINI: Right, this one.

MR. WARNICK: -- when they're in the repetitive degraded cornerstone column.

DR. CORRADINI: Right. They're in Column Four.

MR. WARNICK: We'll be beginning a 95003 inspection.

DR. CORRADINI: So before that occurs --

MR. WARNICK: Actually, it's ongoing, but -- in the on-site inspection process.

DR. CORRADINI: Okay. So before that occurs, you really can't speak to whether or not you see at least a cultural improvement? I guess, to put it another way, to George's question, "Can they remain there forever," my interpretation of your answer was, Yeah, if they keep on showing their attitude. I mean that's kind of how I read it. So do you see an attitude change in terms of the management and how they're addressing these more of which are called kind of underlying issues, or can you not even say that until you go onsite and do the analysis?

MR. WARNICK: Well, actually, I was about to that, but we want to talk about the hypothetical. In my real day-to-day inspections, through our baseline inspection process, one of our procedures is 71152, which is problem identification and resolution. And on an ongoing basis, I evaluate their performance improvement plan and what they're doing to correct their problems. We'll just do that at a higher level by doing a 95003 inspection.

And I've absolutely seen over the last six months or so a change in direction from the licensee. They've actually changed a number of licensee management, senior management. And so I'm out there interacting with the front-line people day to day. There's a lot of excitement out there. The employees recognize, too, that there have been some onsite problems and, yet, things didn't change, due to the culture that was there.

There's excitement out there. People are excited with the management and the direction that they're going.

DR. CORRADINI: Positively, you're saying?

MR. WARNICK: Positively, absolutely. And that to me are the beginnings of cultural transformations, when people and behaviors are starting to change. We're still identifying findings. It's not a quick change, and it's not something that's easy to change. There's over 2,000 employees out there working every day, but I see indications that they're going in the right direction.

DR. APOSTOLAKIS: But what is it -- can you -- you said that the degradation started around 2004 in performance. Right?

MR. WARNICK: That's when we -- it really started to become evident to us.

DR. APOSTOLAKIS: Okay. Maybe a year before, or something like that. Do we know why? I mean can you correlate it to some change that happened somewhere? I mean what was it that, you know, made a plant that was operating so well for ten years start, you know, deteriorating? What was the reason?

MR. WARNICK: Well, I can tell you what the licensee identified, and then I'll tell you what we're going to do to look into that.

What the licensee identified through their investigation is that -- I talked about it briefly -- they made some key alignment changes to their management, which caused them not to focus on day-to-day activities or -- I'm sorry -- to focus more on day-to-day activities and not so much on long-term planning, equipment reliability, accountability, and things like that.

They started to try to change programs and the way they oversaw maintenance, procedures and different things like that. And we've seen currently in the findings that we have, a few of them were able to look back and see that, Oh, yeah, that was a result of some changes that they made years back, you know, as far as eight or nine years ago.

And what we're doing -- under our current process as the 95003 inspection team, as part of their scope, they're looking back to some of the diagnostic assessments that were done, some of the key changes. Re-engineering is something that Palo Verde talks about that was done in -- I believe it was late -- around 1994 or so -- some of these big changes or key changes at the site that took place, to see if we can go back and identify maybe some of the contributing causes to their performance declining to where they are today.

DR. MALLETT: Greg, let me add that the licensee came in and talked to the Commissioners in a meeting here July 24. And I thought their senior leader said some things very insightful about this. And they asked themselves the same question: What happened. And part of it they said was they grew to accept things over a period of time that they didn't accept before, and so, without their knowledge, the standard changed.

Because if you -- for example, we noticed in the operators, if they put out a request to engineering and engineering comes back in with an answer that's not satisfactory, and they say, Well, that's okay; I'll let it go this time. But if they do that a number of times, the standard changes to where they accept less and less. And they indicated that's what was happening over a period of time.

The other thing is they started thinking they were great. And they were talking about -- we asked them did they go to other licensees to benchmark. And their answer was very interesting. They said, We did, but we were looking at it from, "Why aren't they doing it like we are," not from, "Could we do it any better."

And so I think that some people call that complacency. I call it the standard erosion to where they -- you think you're good, but you aren't still looking to see how good you are.

DR. APOSTOLAKIS: Yeah. That's good.

MR. MAYNARD: I think we need to be --

Have you got another question?

DR. APOSTOLAKIS: Yeah.

MR. MAYNARD: We need to be wrapping up here soon if we want to eat.

DR. APOSTOLAKIS: Yes.

Can you explain value added through ROP? The value's added to what or to whom?

MR. WARNICK: Well, value added to safety is what I would get. In our efforts in identifying a lot of these issues, as I tried to illustrate, in many cases, we were ahead of the licensee in identifying their declining performance.

DR. APOSTOLAKIS: But did you -- excuse me.

Mr. WARNICK: And the value that comes from that is: As we identify them, as we issue inspection findings, the licensee has to take a step back and look at our assessment that we're giving them and see where they can better --

DR. APOSTOLAKIS: But the question is really whether it's the ROP itself that is adding the value, because wouldn't you say that before the ROP came along, you would still have found these things? What is the specific thing that the ROP added?

MR. WARNICK: Well, what I see the ROP added is -- we talked about the action matrix and where the oversight of Palo Verde has come. And Bruce talked a little bit about turning up the gain.

It allowed us to step in and then provide additional oversight in a systematic manner. It gives us the tools -- substantive cross-cutting issues, confirmatory action letters, and different things -- as we step through that. As we recognize the degraded/declining performance, we use the oversight that's mandated by the revised oversight process so that we can gain the assurance that we need that the licensee has turned themselves around and that they are turning their performance to a level that we desire for them to be back to the licensee response column. And --

DR. APOSTOLAKIS: Is it because before the ROP, a lot of these things perhaps would have happened, but not in a structured way? Is that what you mean? Now it's a more structured way of approaching it? And --

DR. MALLETT: You answer it, Greg, and then I'll --

DR. APOSTOLAKIS: Because I can't imagine that you guys wouldn't be doing --

DR. MALLETT: We'll see if we match.

MR. WARNICK: Well, first of all, I came into the NRC at the tail-end of the SALP. I'm sure Bruce can talk a little bit more to that process. But that -- I was here under the tail-end of SALP and the transition of ROP. And that's -- the big thing I saw is there was a lot more structure under the ROP.

DR. APOSTOLAKIS: Because I agree that the structure is there.

MR. WARNICK: And it was that structure that provided us a systematic way to step through and approach these declining performance issues.

DR. APOSTOLAKIS: Yes. Thank you.

DR. MALLETT: I would add something else I've seen the ROP do. Not only has it put risk into the equation to discuss the significance of things and put some rigor into that for consistency, but it has gotten us to talk to each other much more than the old program. I see us sharing things in discussions like we're having today that we didn't do before. I don't know if that's credited to just the ROP or the sign of our times, but I think that's valuable.

The other thing is we have built into the process changing it to focus on different areas like, as we see a voiding as an issue, then we go out now with NRR and look, Well, should we be focusing inspections on voiding now. And the component design inspection grew out of that concern. So I think it's the sharing of those lessons learned that I see more in the ROP, as well as the structure that it puts into it now.

MR. MAYNARD: Okay. We do need to be wrapping up. We have time at the end of the day, a roundtable discussion, where we can go back to any of these discussions.

One thing I'd like to just say for the record: I've limited my discussion on especially two of these plants because I have conflicts. I'm on Cooper's onsite safety review committee, so I've been careful of what I say there. Also, for Palo Verde, I did participate in an independent industry assessment in 2005 for the senior management of APS. So there were some conflicts there. So I've limited my comments on those two things.

The other thing for the record that I think needs to be stated: We've heard the Region IV's perspective on the Reactor Oversight Process and on these; we did not invite the licensees in or provide any time for them. They may or may not have any different perspective. I mean we just need to acknowledge that. I don't think there has been anything said that would be misleading or anything, but we have only heard the one side of it for those -- the purposes here.

So with that, I'd say we take a lunch break, and let's be back at 12:30.

MR. GODY: Thank you.

A couple of administrative items. The lunches: If you ordered a lunch, there's the lunches sitting at the back. There's unsweetened ice tea and water. And in the cooler, there's some ice. You can also get soda in the refrigerator. If you come out this door, you make a right, and there's a small cove, and there's a little refrigerator in there. And there's sodas in there for 50 cents apiece.

Also, if you did not order lunch, there's -- we'll have escorts available for you to go down to the cafeteria in the building next-door. So just let me know.

(Whereupon, a luncheon recess ensued.)

MR. MAYNARD: Okay. Let's go ahead and call the meeting back to order. Next on the agenda is a tour of the incident response center. And we're going to go off the record for that, for the tour. So we won't be needing the transcript.

One question I'd have for you. I'm not sure. Are members of the public invited on this part of the tour? Or --

MR. GODY: No, they're not.

MR. MAYNARD: No? Okay. With that, we'll turn it back over to you for the logistics for the tour.

MR. GODY: Thank you, sir.

What I'd like to do is -- we'll just gather up, go in the elevator and go up to the fifth floor and go to the incident response center. And Linda Howell is waiting for us there.

(Whereupon, participants toured the incident response center.)

MR. MAYNARD: I believe that we've got at least most of the people back here. We can go ahead and get started again, get back on the record.

Our next topic's independent spent fuel storage. We don't -- we're running a little behind schedule, but we don't need to make it all up on your presentation --

DR. SPITZBERG: Okay.

MR. MAYNARD: -- so you have more than five minutes.

DR. SPITZBERG: All right. Well, I haven't timed mine sufficiently to know exactly how long it will take, but I'll try and get done within the time allotted.

Thank you. My name is Blair Spitzberg. I'm the chief of the fuel cycle decommissioning branch here in Region IV. And my branch is one of the branches that captures a couple of areas that intersect with the reactor programs.

My programs are not NRR programs; they're primarily the decommissioning program and the independent spent fuel storage installations programs, which are both in the FSFME office in headquarters and NMSS. But we do get out to the reactor sites and we do perform inspections at operating facilities.

What I wanted to discuss today are just a couple of -- a few examples of some of the issues and challenges that we have faced in these two areas over the past several years, in both decommissioning and spent fuel storage.

We have -- I know that the agency is preparing itself for a wave of new license applications in the reactor arena, but for those of you who go back a number of years like myself, you remember the day when nuclear reactors were prematurely shutting down and going into a decommissioning mode.

There's a lot of reasons for that, one being the fact that we had an accident at Three Mile Island, and the Chernobyl accident led to a lack of confidence on the part of the public. But nevertheless there was five reactors in Region IV alone that decided to prematurely shut down.

And some of those reactors we've terminated the license of and completely seen them through decommissioning, and others are in the various processes of decommissioning. The ones that are still in decommissioning process are Humboldt Bay in northern California, and San Onofre, which is this plant that you're going to be visiting later this week.

MR. MAYNARD: You might clarify it's San Onofre 1.

DR. SPITZBERG: San Onofre Unit 1, that's correct.

MR. MAYNARD: We'll still have units operating.

DR. SPITZBERG: The licenses that we've decommissioned successfully and terminated in license in Region IV by the way is the Trojan facility, the Ft. St. Vrain facility in Colorado, and the Pathfinder facility in South Dakota.

MR. MAYNARD: How about SMUD, whatever that was?

DR. SPITZBERG: That was Sacramento Municipal Utility District. That one is still in decommissioning, also. I forgot to mention that one up near Sacramento.

I want to focus a little bit on the San Onofre

Unit 1 site here, since that's the one that you're going to be out there later this week. They had an operating license from '67 to 1992. Dismantlement is currently in progress.

I've got two photographs here that one shows the old reactor facility back when it was -- actually had just gone into operation, I suppose, and you can see that you were able to drive up virtually to the front door of the facility. The second one is a picture taken, on the right hand side, just recently. I think this last part of the containment has now been dismantled and is gone now. This was just a few weeks ago.

All of the fuel from the Unit 1 site is currently in the ISFSI on site. This is one of the sites that they did have an experience with some tritium in the groundwater underneath the site there that they've dealt with in recent months.

And the topic that I want to discuss today is the disposal of the grouted reactor pressure vessel which still remains unresolved. In this picture over here you see the reactor pressure vessel still sitting on the site.

DR. WALLIS: Would you explain something about how it's grouted?

DR. SPITZBERG: Yes, they -- what they do is they have to -- they were proposing to send it for disposal at a shallow land burial site.

DR. WALLIS: How is it grouted. I don't --

DR. SPITZBERG: It's grouted with low-density concrete.

DR. WALLIS: So it is a pressure vessel covered with concrete?

DR. SPITZBERG: No, the pressure vessel is still filled with --

DR. WALLIS: With concrete.

DR. SPITZBERG: -- low-density concrete.

DR. WALLIS: Oh, they filled it.

DR. SPITZBERG: They filled it with it, and that's to immobilize the contaminants inside --

DR. WALLIS: I see. Okay.

DR. SPITZBERG: -- and make the package satisfy the package requirements for transport.

So anyway, the licensee came to us several years ago and indicated to us that they were looking at options for how they would dispose of their reactor pressure vessel. And I wanted to go through some of the options now, because one of the things that this illustrates is the problems that we have with low-level waste disposal capacity in this country.

MR. MAYNARD: Please refresh my -- Trojan went to Hanford, is that what they did with it?

DR. SPITZBERG: Trojan went to Hanford, and they're part of the Northwest Compact, so that --

MR. MAYNARD: I see.

DR. SPITZBERG: -- they had clearance to dispose of the reactor vessel there.

DR. SHACK: And though this is nice and conveniently located, you can't --

DR. SPITZBERG: Yes.

DR. SHACK: -- go there.

DR. SPITZBERG: That -- well, that's right. So this was the first option they looked at was putting it on a rail car and transporting it to Barnwell, South Carolina, which is the site over here, which is the only available waste burial site, low-level waste burial site, available to the San Onofre site at the time.

There actually is a low-level waste burial site, as you're aware, Energy Solutions in Utah, but they're not able to take anything other than Class A waste. So the reactor vessel could not be shipped there.

They did not have the option to go up to the waste burial site up in Washington because they're not part of that compact. See, I don't --

DR. ABDEL-KAHLIK: Classified as what, Class C?

DR. SPITZBERG: It would be Class C waste. The options they looked at here, when they approached the railroad companies, and I'm not sure which route they were looking at, but it's probably one of these two southern routes. This is a map showing the rail transport routes, corridors, in the U.S.

I refer to this -- these routes as the Vasquez De Coronado route. I'm an amateur historian here. But in any case, the railroads were concerned that if there was an accident on one of these two routes, that it could put their route out of service for a period of time that the railroads apparently conveyed back to the utility that they were not willing to take these -- this shipment by these routes.

So then the --

DR. SHACK: But they physically could take it.

DR. SPITZBERG: They could take it, yes. So then they turned to option two, which was transport by sea barge through the Panama Canal to Barnwell, and, of course, the utility had located a sea barge that was built I think back before World War II, and they had deemed it unsinkable because it had water tight compartments and it was an --

MR. MAYNARD: The Titanic --

DR. SPITZBERG: -- unsinkable barge.

MR. MAYNARD: -- was unsinkable too.

DR. SPITZBERG: I'm sorry?

VOICE: So it wouldn't be able to sink.

DR. SPITZBERG: That's right. But in any case, they were going to ship it down through the Panama Canal to Barnwell via this route, which I have termed the Vasco de Balboa Route.

Unfortunately, this route was not approved, as I understand it, by the canal zone, the Panamanian were concerned about transporting this type of package through the canal zone and what were to happen if something were to go wrong with the transport as it passed through the canal. So they did not get clearance to go by this route.

So the next option they looked at was the transport by the same barge, the unsinkable barge, around Cape Horn, South America to Barnwell, and I guess I'll refer to this as the Sir Francis Drake route.

And the problem with this is that, among other things, it's a very long route, as you can tell. But the State Department, as I understand it, received concerns all the way up to the Secretary of State, which was then Colin Powell involving concerns expressed by the South American countries who would be considered safe harbor in the event of some event or foul weather, or something where this barge carrying this reactor vessel had to put into port for whatever reason on this route.

So they got this feedback from these countries and the State Department was opposed to this, so I think the utility gave up on this idea and abandoned this.

So consequently here stands the Unit 1 reactor pressure vessel still packaged in its transport package ready for shipment with no place to go. And their plans currently, as I understand it, is to leave it on site until the other units are decommissioned decades down the line and then dispose of it with the other reactors at that time via whatever mechanism is available at that time.

DR. WALLIS: Well, it can't be very harmless for people -- very harmful for people standing around it.

DR. SPITZBERG: Yes, it's -- well, it's relatively well shielded, but it is -- you do get some radiation readings off of it. One of the things that I think -- I wanted to highlight by illustrating this problem that SONGS encountered with disposal of the reactor vessel is that, as a healthy physicist, I think most of us would be strongly in favor of going ahead and disposing of this material, getting it in its final resting place so that you don't have to deal with it in health physic space.

But if you recall back to the Low-Level Waste Policy Act of 1982, it laid out the format for the states to encounter into agreements with other states into what they call compacts. And then each of these compacts would agree on developing their own low-level waste disposal sites.

And my understanding of the compact system, based on what I see, is that it was not successful in developing additional alternatives for low-level waste disposal.

DR. SHACK: Just -- in that package now, did they take out things like baffle former plates or all that irradiated stainless steel --

DR. SPITZBERG: They did take out some of the internals that would have caused the package to be greater than Class C, because they could not dispose of greater than Class C at the low-level waste burial sites, they would have to go to the high-level waste sites. And so that was removed.

The other area in the reactor decommissioning arena --

DR. ABDEL-KAHLIK: What happened to those internal components that were removed?

DR. SPITZBERG: That will be packaged up and put in their ISFSI and eventually sent to a high-level waste disposal facility, could be Yucca Mountain, could be whatever other facility.

(Pause.)

DR. SPITZBERG: Okay. The other issue that I want to briefly describe in the reactor decommissioning arena has to do with the Humboldt Bay facility which is on the northern coast of California. Humboldt Bay, for those of you that don't know, was a small BWR that operated back in the '60s.

It was very unique in that it was right on the coast, and it is also subterranean. It's been in safe store since -- it's been permanently shut down since about 1976. And a couple of years ago when they were preparing to make their plans for putting their spent fuel in dry cask storage, they decided that they needed to go into their spent fuel pool and do a comprehensive inventory assessment of the fuel that they have there to make sure that that aligned with their current records and inventory of their special nuclear material.

In the process of doing that, they discovered that there were three small rod segments that were unaccounted for. And these rod segments were cut back in 1968 time frame. They packaged it originally with the intent of shipping it off site to a laboratory for some examination of the fuel and it had performed. They have records that indicated that the shipment never took place, and that they placed the fuel back in the pool.

But from that point on the records did not account for where the segments were. And so when they were going through and trying to reconcile the records they had on hand and the fuel, that they went through their inventory and visual examination with the underwater cameras, and they could not account for the segments.

So they notified the NRC and started an extensive and investigation, which took several months to complete. And at the end of that search and investigation, they failed to positively identify the segments.

DR. CORRADINI: So this was spent fuel?

DR. SPITZBERG: This was spent fuel.

DR. CORRADINI: And it was three rods, or three part --

DR. SPITZBERG: It was three segments of a single rod, three 18 inch --

DR. CORRADINI: Three segments --

DR. SPITZBERG: -- segments.

DR. CORRADINI: -- of a single rod.

DR. SPITZBERG: Yes.

DR. CORRADINI: So it was 100 grams or something?

DR. SPITZBERG: I don't remember the exact weight -- the mass -- are you talking about the mass of the special nuclear material?

DR. CORRADINI: Right.

DR. SPITZBERG: Yes, I don't remember. Do you --

DR. CORRADINI: But -- I guess you used that phrase again, but it's not special nuclear material, is it?

DR. SPITZBERG: It's irradiated fuel.

DR. CORRADINI: So is that by definition, by these definitions, special nuclear material?

DR. SPITZBERG: It is special nuclear material.

MALE VOICE: Yes, sure.

MALE VOICE: Yes, sir.

DR. MALLETT: About 5 percent.

DR. SPITZBERG: Because it's --

DR. MALLETT: Right around 5 percent. I don't know what this --

DR. SPITZBERG: It was about 5 percent as I recall.

DR. CORRADINI: Oh, so it's fresh.

DR. SPITZBERG: It's not -- it's irradiated fuel, previously irradiated fuel. It has been burned in their reactor.

DR. CORRADINI: So --

DR. SPITZBERG: But it was still very fissile. Okay. So after their investigation, and, of course, we were heavily involved in that investigation as well from an inspection standpoint. What the licensee concluded is that the most probable scenario was that after the spent fuel pool clean up effort years ago, they'd mistaken -- mistook these fuel rods segments for low-level waste and put it in a low-level waste shipment to a burial site in South Dakota I believe was the one that they identified there.

That was the most probable scenario. They also looked at all the other possible scenarios and gave weight to those scenarios based on the evidence that they had developed in their investigation. And subsequent to that they were subject to NRC enforcement action and a civil penalty.

The next topic that I wanted to discuss briefly was to check some of the challenging Region IV inspection issues in the spent fuel storage arena. I know there was a question this morning about ISFSI. I just wanted to make sure we're clear on the terminology here.

Three areas that I wanted to discuss, one, the canister handling crane issues, the second being the use of a lightweight transfer cask, and then I wanted to discuss one case of an ISFSI construction project with some ongoing legal issues.

On the cask handling crane issues, this was a plant here in Region IV that had some seismic analysis concerns with the crane supports that we identified during the pre-operational inspection of their ISFSI operations. We also have identified irregularities with the 125 percent load tests that were conducted in 1980 with the cask handling crane at another site.

At the first site where we had the seismic analysis issues, we also found lost documentation of crane weld inspections back when they were originally performed. We've also identified crane maintenance issues. And with single failure proof cranes, one of our sites we identified a number of issues in the pre-operational inspection having to do with things like hoist gears were dry and galled, they had inoperable systems associated with the crane, including the wire rope equalizing system, the bridge and trolley limit switches, the crane load hang-up protection.

There was some gearbox lubricant issues concerning whether or not they were using the proper lubricant in the gearbox, and inadequate cold proof tests that had been performed.

And so based on this, fortunately we caught these in the pre-operational inspections, so it did not involve the use of cranes with actual lifting of the loaded canister. The licensees in all of these cases did take corrective action and corrected these problems prior to the initial cask loadings.

The next area that I wanted to talk about in the ISFSI arena that we've encountered in recent years has to do with the use of a lightweight transfer cask at a plant in Region IV. They opted to use a lightweight transfer cask due to the limitations on their cask handling crane in their aux building which was limited to 75 tons.

Typical weight of a loaded canister is in the neighborhood of about 100 tons, and so they needed to do something if they wanted to use the 75-ton crane capacity. They did this by removing about 25 tons of shielding from the transfer -- from the canister and from the transfer cask, and they did this under what we call the 72.48 process which is the equivalent of the 50.50 -- roughly equivalent of the 50.59 process, the self-approval process.

We learned about this prior to the actual loading and we did our pre-operational inspections and started asking questions about the 72.48 process that they put this through. Some of the things that we found out is that they removed enough of the shielding that they would have, for design basis, fuel radiation levels on a loaded canister up to 53 Rem per hour.

They also had planned -- in order to compensate for the reduction in shielding, they planned to use remote crane operations, including cameras and laser sites, which is well and good until a problem occurs or if it gets hung up there. Then you have to counteract the problem with the remote handling.

The canister drain-down was also going to occur earlier than specified in the FSAR, which potentially affected the vacuum drying times tech spec limit for the canister. And this is a tech spec limit that is intended to protect the cladding on the fuel.

After we looked at this and we got our spent fuel project office involved and the experts up there, we did a lot of analysis and determined that the changes that were being proposed by the licensee could not be self-approved under the 72.48 process.

We caught this before they loaded -- were loading casks, so the licensee subsequently sought and received NRC exemption, but the exemption that they sought was only for the old cold fuel, it was not for the design basis fuel, and exemption limited them to being able to load only four casks.

And so now we have this licensee up there and they're starting to plot their future in terms of what do they need to do now to load casks with the 75-ton crane, and I think what they're contemplating now is upgrading the rating on the crane, putting in a new crane essentially.

As a result of this, there was a regulatory issue summary that was issued in 2006 that contained a lot of the lessons learned from this episode.

MALE VOICE: This is kind of interesting here.

DR. ABDEL-KAHLIK: They were going to go through this process through 72.48. What was the mechanism by which you sort of caught them in mid-stream and said, no, you can't do it, you have to have approval?

DR. SPITZBERG: We -- our program requires us to do a pre-operational inspection prior to the first cask loading at each site. And so as part of that pre-operational inspection, we do look at the 72.48 process that the licensee uses, because all of these licensees that use these pre-approved casks, they always make some site specific changes to the way that they're going to us them.

And so we look at the 72.48 process to make sure it's consistent and properly applied. And that's where we caught it, is in the pre-operational preparations to load casks.

DR. ABDEL-KAHLIK: So the vendor of this cask did not seek approval of this --

DR. SPITZBERG: Yes.

DR. ABDEL-KAHLIK: -- modified --

DR. SPITZBERG: That's correct.

DR. ABDEL-KAHLIK: -- cask with one --

DR. SPITZBERG: That's correct.

DR. ABDEL-KAHLIK: -- shield.

DR. SPITZBERG: And if you were to talk to the vendor, they would probably contend that they still don't need to seek approval. But it was our agency decision that in this case they did.

The last area I wanted to briefly talk about is the inspection of the Diablo Canyon ISFSI. You're probably aware that there have been some recent legal challenges regarding the consideration of terrorist attacks in conducting the Diablo Canyon ISFSI environmental reviews.

In the meantime, while this has been going on, Region IV has continued to conduct our time sensitive inspections of the construction and pre-operational areas of the Diablo Canyon ISFSI because the licensee has proceeded to go down the path of constructing their ISFSI, the pad, the transporter, a lot of the infrastructure that supports their eventual use of this system has been under construction. and so we've performed our inspections during the sensitive phases of those construction activities.

Inspections to date include the fabrication of the transporter, which in the case of Diablo Canyon, it is in a seismically -- elevated seismic area out there, and so they do have an important safety transporter, and we've observed -- inspected the fabrication of that transporter, the construction of the transport roadway, the ISFSI pads, and the transfer facility for the casks, and also the installation of the grouted rock anchors and transporter seismic tie-down.

We've conducted these inspections as if there were no ongoing legal challenges to the process.

DR. CORRADINI: So the challenges are for the eventual granting of the license for the dry cask storage facility.

DR. SPITZBERG: Yes. Well, essentially the challenges would intervene in their ability to load casks --

DR. CORRADINI: Right.

DR. SPITZBERG: -- under this --

DR. CORRADINI: I sorry.

DR. SPITZBERG: Yes.

MR. SHUKLA: So the license has been granted?

DR. MALLETT: Let's make that clear. They have a license to load fuel. We've approved it.

DR. SPITZBERG: Yes.

DR. MALLETT: But since that time it's been challenged in the courts --

DR. SPITZBERG: Correct.

DR. MALLETT: -- that the environmental assessment was not adequate because it didn't consider --

DR. SPITZBERG: Consider terrorist attack.

DR. MALLETT: -- security, terrorism. That's what we resolved in that analysis.

DR. SPITZBERG: Thank you. So with that, I'll just end with -- I know you're going to San Onofre, so I'll just end with another depiction of their ISFSI out there with their little transporter here that -- and a couple of NRC inspectors down below.

DR. CORRADINI: So I guess -- I have to go back to the one where the fuel segments are kind of missing.

DR. SPITZBERG: Yes.

DR. CORRADINI: So you fined them and then?

MALE VOICE: We didn't fine them.

DR. SPITZBERG: We didn't fine them.

DR. CORRADINI: Didn't fine -- not -- you didn't fine -- the segments -- they were civil penalty fined.

DR. SPITZBERG: Yes.

DR. CORRADINI: And then the operator -- what is -- legally it's done now, it's just somewhere in the environment, end of story?

DR. SPITZBERG: Well, the scenario that they believe has the most credibility, based on all the various scenarios that could have occurred with the fuel, was that it went to a low-level waste burial site with some other low-level waste by mistake.

DR. CORRADINI: And in your calculations --

DR. SPITZBERG: Now, there is still the potential that the fuel is still there in the pool in an unrecognized form, or in another canister that they -- mixed in with some other fuel and they don't recognize exactly -- there were not serial numbers on them.

DR. CORRADINI: Right. I understand. But I guess my mind's going on a few things like so it must have been a small enough amount of fuel that you do -- there's some sort of radiological scan of low-level waste coming off site to make sure that what you think is there is approximate in terms of the radiation level that's out there. So it's got to be low enough that it passed that screen if it went to the low-level waste site.

DR. SPITZBERG: That's correct. It --

DR. CORRADINI: So did they do a radiological --

DR. SPITZBERG: They did look at their shipping records for their waste and they did find that the radiation levels for those shipments met transportation regulations. However, these are usually low-level waste shipments from nuclear plants can include spent resins --

DR. CORRADINI: Yes, it depends --

DR. SPITZBERG: -- and other things. So it can be pretty hot.

DR. CORRADINI: Right.

DR. SPITZBERG: And it has to be -- for example, if you ship spent resins, it's just normally in a shielded container. So if it was in a shielded container like you would send spent resins in, they found it credible that it could have been mixed in with this material.

DR. CORRADINI: All right. Thank you.

MR. MAYNARD: They -- I'm not sure what was going on in that time, but typically it also gets scanned when it arrives at the facility.

DR. SPITZBERG: That's correct.

DR. CORRADINI: Great. Great. That's where I guess I was going.

DR. SPITZBERG: Yes, and one of the questions that frequently will come up in this scenario that we might not have asked ourselves quite as intensely back before 9/11 is, what if somebody wanted to make off with this for the wrong reason.

DR. CORRADINI: Right. But Said was asking that question. I guess the mass level is such that --

DR. SPITZBERG: Well, the mass level would not be enough to make -- for strategic purposes. But if you wanted to make a dirty bomb it would make -- but they were able to conclude that that -- the probability of that occurring was very small because of the network of radiation monitors and physical security that they had on the building and the spent fuel pool where this was being stored. And we believe that this is also credible.

MR. MAYNARD: Okay. If there's no other questions, thank you. And we'll move on to the next presentation on safety culture.

DR. MALLETT: But let me add something before these gentlemen leave. This is Vince Evert on the left, Scott Atwater also on my left and nearer to me. He and -- these two individuals, and there's another individual named Ray Keller, are some of those experts we want to retain. They'll probably ask me for more salary after this, but they are experts in this area.

And I think Region IV is -- you asked what are the differences, we probably have a center of excellence here in this area for independent spent fuel storage installations. In fact, they're doing inspections at other facilities in other regions because of that expertise. I just wanted to point that out.

MALE VOICE: Thank you.

MR. MAYNARD: Okay. I think you're ready for Linda and Roy, with safety culture.

MS. SMITH: We're coming. That works. Okay. This is the designed after-lunch nap. I'm just kidding.

What I want to do today is to go over the steps that we've done and taken to implement the safety-culture initiative program and effectively here. And I noticed when you all got the action matrices handed to you, that was just sort of a little bit on context, and I thought the same amount might be helpful here.

So I wanted to let you know that the action matrix is driven by inspection results basically. And we have three different kinds of inspections, and they all produce findings. And when you have a greater than green -- or a greater than minor finding, then it's going to have to be evaluated for significance to see how far you go on the action matrix.

And this is also -- that same finding will be evaluated to determine whether or not it's a cross cutting aspect, has a cross-cutting aspect associated with it. And that would then be subsequently identified for substantive cross-cutting issues.

So simply there's a pot of inspections, they produce findings, the findings get evaluated by significance and go down the action matrix path, and they get evaluated as whether or not they are causal factors to go down the other path.

Okay. During the safety-culture initiative, what they did was try to identify the most important things for safety culture so that you would assess your working conditions, or your situation to see if you had implemented those things. And those are what they call the safety-culture components.

The Commission directed the staff to enhance the reactor oversight process to more fully address safety culture, and the three cross-cutting areas, problem identification and resolution, human performance and safety-conscious work environment have long been recognized as a foundation for the ROP.

But the safety-culture initiative identified that the components of each of the cross-cutting areas which need to be present for an effective safety culture to exist. So they're all written in the positive, and then we evaluate them in the negative.

In total there are 13 safety-culture components, nine components were evaluated during the baseline inspection, and those are the ones that are listed. And there's a remaining four that happened with the supplemental inspections.

This is just one more shot at trying to go over the structure. You've got the cross-cutting areas and the ROP always had human performance, and problem identification resolution and safety-conscious work environment. What got changed was which ones were used to evaluate safety -- substantive cross-cutting issues, you know, cross-cutting aspects being evaluated as groups to the subsequent cross-cutting issues.

DR. WALLIS: But these are all components -- excuse me. How do you measure them?

MS. SMITH: We don't measure them like a number, but the way --

DR. WALLIS: But you must have some --

MS. SMITH: -- that you utilize them.

DR. WALLIS: -- way of assessing them.

MS. SMITH: Yes, there is a way.

DR. WALLIS: Which is not a measure but it's a kind of a measure, qualitative measure.

MS. SMITH: Yes, that's true.

DR. WALLIS: It's a description.

MS. SMITH: Yes. What --

DR. WALLIS: How is it done, how do you do those -- how does it -- how do you know whether it's good or bad or indifferent, or -- how did you give it an A, B or C, or whatever you do?

MS. SMITH: Well, the source of these is helpful to understand that answer, is that they come from inspection reports and it's a greater than minor finding. And so you look at the thing and you know you're not -- it's not supposed to happen, it's a performance deficiency, it's a violation. It's not supposed to happen.

You determine that it's greater than minor, which means it's significant enough to be included in this process, and then you look at your violation or performance deficiency and you try to identify if these issues are -- issues is a bad word -- these aspects are things which would prevent you from the deficiency, or cause -- it's like a cause code analysis system.

So these essentially work as little pre-designed root cause -- common cause codes really about an organization. So as you have violations and findings coming in, and you assess those to see if there are any safety-culture components, which are the ones that are listed, that could have contributed significantly towards the deficiency or the violation happening.

DR. APOSTOLAKIS: I think you are not really assessing how well --

MS. SMITH: Right.

DR. APOSTOLAKIS: -- you're not grading or rating, A, B, C.

MS. SMITH: Right.

DR. APOSTOLAKIS: If there is a violation somewhere, and you suspect that it was an issue of human performance, then the way I understanding it, you look deeper and you say, oh, this was an issue of resources.

MS. SMITH: Right. Exactly.

DR. APOSTOLAKIS: And then the licensee I guess, if they agreed with you, will have to do something about it.

MS. SMITH: That's correct.

DR. APOSTOLAKIS: Because otherwise you have the issue of what is a good safety culture, but nobody knows what that is.

MS. SMITH: Right. They know the things that are listed there are all good things. They figured --

DR. APOSTOLAKIS: Yes.

MS. SMITH: -- out these are the components, what you want to look for and have. And it's kind of go/no go, does this look like something --

DR. WALLIS: So you go --

MS. SMITH: -- that could have been caught.

DR. WALLIS: -- back to the licensee for their assessment of how well they did on work control, or whatever it was?

MS. SMITH: Yes. For each time we have a finding that we've evaluated and we think there's an aspect, there'll be dialogue with the licensees during the inspections, at the pre-brief, at the exit. If they find new facts it can be after the exit, after the report's even been written, if it's -- we'll -- but they'd have to put it on the docket.

But we try to get all the facts on the table commensurate with the safety significance, because there -- it would be the very best if we always perfectly knew what the root cause were and we could perfectly --

DR. WALLIS: Suppose you pick the perceptions fo retaliation. I mean, how do you determine something like that in a fair way? Do you have to go down and ask questions of individuals and --

MS. SMITH: Yes. Actually another piece of this initiative was to add a set of questions -- they were there before, but to strengthen them quite a bit -- to the problem identification and resolution inspection. And there's kind of two ways that sort of thing would come up. One is either through the allegation process, or it will come up in this safety-conscious work environment survey.

And so in both cases it uses slightly different administrative mechanisms. We evaluate what the allegation is, or the assertion is, and then we work through that process to disposition it.

DR. APOSTOLAKIS: But, again, this is in he context of a specific finding, is it not?

MS. SMITH: Yes. These are --

DR. APOSTOLAKIS: They're not going to give out questionnaires asking people, you know, whether they perceive that there is --

MS. SMITH: No.

DR. APOSTOLAKIS: -- an indication --

MS. SMITH: That's true. And --

DR. APOSTOLAKIS: -- a possible --

MS. SMITH: -- it's in the finding, aspect of the finding.

DR. APOSTOLAKIS: In the context of the finding.

MS. SMITH: That's right. It is also true we're going to go ask those questions, but it's not in the context of determining --

DR. APOSTOLAKIS: Right.

MS. SMITH: -- a cross-cutting aspect.

DR. APOSTOLAKIS: You are characterizing the finding.

MS. SMITH: Right. Yes. And by doing that, then once we've had one that we've characterized as a legitimate cross-cutting aspect, which means it had a significant contributor -- it was a significant contributor to the performance deficiency, and also that it reflected currently performance, because like, for example, you might have some old design issue that you find and it's a violation.

But this process is all built with the assumption of trying to modify and improve current performance or safety-culture things. And so you might not include the design one if it was an old issue.

Now, if they've revised the CAP a year ago and should have caught it, you know, then it would be now something which is reflective of more current performance, and it would still be eligible to become a cross-cutting aspect.

MR. MAYNARD: If there's suspicion of wrongdoing or intimidation, harassment, there are other mechanisms --

MS. SMITH: Yes.

MR. MAYNARD: -- available to the agency. It kind of tosses that into a different ball game.

MS. SMITH: Yes. But this -- yes, that's exactly true. But we do still have the possibility, if it comes out and we write a chilling-effect letter, for example, because we've decided it's not isolated and the licensee has something they need to worry about, that'll be something -- and there's was a finding associated with it, then that could be a cross-cutting aspect.

So we could have a SCWE cross-cutting aspect. They're just a little harder to get.

DR. MALLETT: The issue I talked about this morning the licensees are raising is they wanted more definition because prior to this we'd say, well, we have a human performance issue, and they'd say, well, how did you decide that. And it might be I might have one way, Linda my have another one, Roy may have another one. So we said, well, let's put some, what did you call them, components down there, or attributes that we said we could use.

So we gave these to the inspectors. I'm just trying to make a point here. So what happens now, the inspection makes a finding, and they he says, does it have an aspect of one of these sub-components. Yes, it does; I'll put into that bin. The licensees' argument is, there's no threshold.

You've told him he has to find a spot to put it.

DR. WALLIS: There's no measure.

DR. MALLETT: There's no --

DR. WALLIS: There's no --

DR. MALLETT: -- as you indicated --

DR. WALLIS: Right.

DR. MALLETT: -- no threshold amount. So that is an issue. I hope that helps.

DR. WALLIS: So how do you know when it's been corrected?

DR. BONACA: It has to be more than minor?

MS. SMITH: Yes, there is a threshold.

MR. CANIANO: There's a threshold.

DR. BONACA: And how do you define that?

MS. SMITH: At the risk of getting into big trouble.

DR. BONACA: Again, is it a vague definition, or is it a tangible definition, something that --

MS. SMITH: Yes. That is --

DR. BONACA: It does.

MS. SMITH: Yes. It has to be a more-than-minor finding.

DR. BONACA: You have some guidance.

MR. CANIANO: There is criteria.

DR. BONACA: Yes, there is some criteria.

MR. CANIANO: There definitely is criteria. It's in our manual chapter that defines minor violation.

When you identify an issue where does it fall into, is it minor, is it something that's non-cited violation, and there, there is specific criteria.

MS. SMITH: Okay. So just to recap quickly. The original cross-cutting areas are human performance, PI&R and SCWE, and they're comprised -- those are the nine safety-culture components. And you can see how they distribute themselves among the cross-cutting areas.

In the implementation challenges of this phase, though, there's been improvement in Region IV. One of the things that made it better was the manual chapter 03.05 clearly lists all the components and their definitions. That's what we were talking about. And it even has developed a cause code numbering system for evaluating the cross-cutting aspects, and this aids in communication.

And then the thing that I think has been the most effective actually has been the management review of the -- during the morning meetings, during morning meetings you've heard talked about before. One thing we use those meetings for is to go over the enforcement that's being proposed and the findings for all of the inspection reports.

And we've had real strong management presence during -- when these were first being worked on to make sure that everybody was doing them the same way.

DR. ABDEL-KAHLIK: Do you try to correlate the outcome of different findings just to see, even though these might be qualitative, that there may be sort of a persistent trend?

MS. SMITH: Well, we're looking for a persistent trend. And if you have the cross-cutting aspect -- say you have a performance deficiency; you've decided that one of those things is a contributing cause to it and you think it's a current performance -- then that goes in your bucket that you start doing the bin in, and you sort them by themes to try to find the theme.

And then once you get greater than three, you say, okay, I've got a theme, and then you get into the substantive cross-cutting issue. And so the outcome is really a trend analysis.

DR. ABDEL-KAHLIK: Okay.

MS. SMITH: Common cross-trend analysis.

DR. BONACA: The big difference now is that you can trigger a self-assessment based on the three more-than-minor findings in a specific area. That's a difference from the system before?

MS. SMITH: The -- yes, the substantive cross-cutting issues before didn't used to have as many bins as -- now they've got nine; they used to have five or six. And they didn't have safety-conscious work environment before.

And so what they did with the safety-culture initiative was make the bins more comprehensive of the things that you're going to see, and add things to look at for safety-conscious work environment.

DR. APOSTOLAKIS: Are the words "safety culture" anywhere in the --

MS. SMITH: Yes.

DR. APOSTOLAKIS: -- documents?

MS. SMITH: They don't talk about -- the part that I'm talking about now is safety culture directly.

DR. APOSTOLAKIS: Right.

MS. SMITH: They talk about the supplemental inspection stuff, which I'm going to get to.

DR. APOSTOLAKIS: Because I know the Commission was -- especially the chairman -- didn't like those words.

MS. SMITH: Well, and what they're saying is part of it is just kind of like routine work, in the routine work they're going to use the components, safety-culture components.

DR. APOSTOLAKIS: So we're using components --

MS. SMITH: Yes. This is --

DR. APOSTOLAKIS: -- when we're talking about --

MS. SMITH: -- the routine --

DR. APOSTOLAKIS: -- culture.

MS. SMITH: This is -- they call them cross-cutting area components. That's for the nine. But when they add the --

DR. APOSTOLAKIS: When you have a culture --

MS. SMITH: -- four more -- there's four more, and which I'll get to, and then they say safety culture, and they talk about safety-culture assessments.

DR. APOSTOLAKIS: Oh, they do comply by this.

MS. SMITH: Yes. Later on. Okay. Now, this is just to kind of show you -- I'd said in manual chapter 03.05, it laid out the terms. So for safety-conscious work environment, that cross-cutting area you could have an environment for raising concerns, which would be called a cross-cutting component, and it's paragraph S.1(a).

So if you look through the manual, you could find that paragraph number, and it would discuss behaviors and interactions that encourage free flow of information related to nuclear safety issues, differing professional opinions, and identifying issues and the corrective action program and through self-assessment, and that's your cross-cutting aspect.

So the next part is what -- really what we talked about already, the going through the analysis of your cross-cutting aspects. And basically licensees often don't do full root cause analysis, so you've decided something's a significant contributor, but actually you probably don't know in the same way you would know if someone had done a root cause analysis.

But we just kind of had to come to grips with using the available information the best we could to evaluate safety-culture things. And so that's what happens. That's been a little hard for the inspectors to deal with because they like things done perfect. But we're working on it.

And as a result of continued management focus and feedback from the stakeholders, documentation and the basis for identifying a substantive cross-cutting issue and an assessment letter has also been approved.

Now, here you take that group of four or five or ten substantive cross-cutting aspects that have the same themed -- or cross-cutting aspects that have the same theme, and you propose a substantive cross-cutting issue, and you would do that if you were -- you believed that -- you didn't think -- you didn't confidence that the licensee would fix it. This is the place --

MR. CANIANO: This is place --

MS. SMITH: -- where the confidence --

MR. CANIANO: -- where the criteria --

MS. SMITH: -- comes in.

MR. CANIANO: -- is that we talked about.

DR. APOSTOLAKIS: So a weak aspect becomes an issue, is that what it is?

MS. SMITH: Yes, if you clump together the aspects --

DR. APOSTOLAKIS: Or maybe than one aspect?

MS. SMITH: Yes, you have to have greater --

DR. APOSTOLAKIS: Yes.

MS. SMITH: -- than three. But practically speaking we usually look for more than that. We look for, you know, a good solid trend. And --

DR. APOSTOLAKIS: You made that a three?

MS. SMITH: Number -- the number three. So if I have three findings, and the period is the six months of the assessment plus the six months before that, so you look back for a 24 month period together. And if they had -- for the aspect we were talking about before, which was the cross-cutting aspect on environment for raising concerns, if -- well, that's not a good idea --

DR. APOSTOLAKIS: If they are sleeping in the control room --

MS. SMITH: Yes.

DR. APOSTOLAKIS: -- we have to catch them three times, or --

MS. SMITH: Oh.

MR. CANIANO: No.

MS. SMITH: No, but that would be like --

DR. APOSTOLAKIS: What is this, a --

MS. SMITH: -- event driven --

DR. APOSTOLAKIS: -- component, an aspect, what is it, can you tell me? Suppose you catch them asleep.

MS. SMITH: That's the finding. The performance deficiency is he's sleeping. But then you've got to say, well, what caused him to be sleeping, what on that list.

DR. APOSTOLAKIS: That's probably serious enough.

MR. CANIANO: That's just an example, we go well beyond this.

DR. APOSTOLAKIS: So -- I'm sorry.

MR. CANIANO: That specific example --

DR. APOSTOLAKIS: But why? Why? I'm trying to understand --

MS. SMITH: When I said in the beginning --

DR. APOSTOLAKIS: -- is there something else where you can put it in --

MS. SMITH: Yes. Yes. Well, there's a lot of things, but the three inspection types that we have, you know, one would be the -- is the event driven one that responds to events and things like -- to make sure they're handling it, and it can be a special inspection, an AIT, an IIT --

DR. APOSTOLAKIS: But this is the mechanics of it.

MS. SMITH: Yes. And those are all --

DR. APOSTOLAKIS: They are sleeping. That to me would be a human performance issue.

MS. SMITH: Yes.

MR. MAYNARD: Well, there's a big difference between one isolated case, and if you have that plus you find other evidence of other things going on.

DR. APOSTOLAKIS: But this is so important.

MR. MAYNARD: But there's a way to handle the single significant activity there.

MR. GODY: Right. If operators are sleeping the control room, operators are governed by 10 C.F.R. Part 55. Each operator has their own license, they're held to high standards, and they would be dealt with under the enforcement policy. So there's --

DR. APOSTOLAKIS: In the action matrix, where does that go? Is that a degraded cornerstone there, or what?

MR. GODY: Well, it's -- the initial actions are dealt under the traditional enforcement policy. Whether or not there's other aspects, I'll let Linda talk about that --

DR. APOSTOLAKIS: Okay.

MR. GODY: -- and how we would deal with those other aspects.

DR. APOSTOLAKIS: I guess the --

MS. SMITH: Are you really asking --

DR. APOSTOLAKIS: The question, it's an honest question --

MS. SMITH: Okay.

DR. APOSTOLAKIS: -- nothing else.

MS. SMITH: No tricks.

DR. APOSTOLAKIS: How do issues related to human performance enter the action matrix?

MS. SMITH: Well --

DR. APOSTOLAKIS: Because it's a cross-cutting issue.

MS. SMITH: -- that's --

DR. APOSTOLAKIS: It affects a lot of things.

MS. SMITH: That's why when I started I thought maybe we needed some context information, is the action matrix deals with the significance of findings. And if the finding is evaluated during our significance determination process to be green, you'll be in that first column. If it's white you go --

DR. APOSTOLAKIS: Oh, okay.

MS. SMITH: And that's only significance. But --

DR. APOSTOLAKIS: So then I would go to --

MS. SMITH: -- the other side --

DR. APOSTOLAKIS: -- the PRA -- assume that the operators are sleeping --

MS. SMITH: Yes.

DR. APOSTOLAKIS: -- I can see how that affects the core damage frequency.

MS. SMITH: Well, I have never done any --

DR. APOSTOLAKIS: And that would give me --

MS. SMITH: -- in that column.

DR. APOSTOLAKIS: -- probably a yellow or a red.

MR. BONNETT: But there is a bigger issue that says that --

MR. GODY: Now, hold on. I'm going to give the microphone to Paul Bonnett.

MR. BONNETT: Hi, this is Paul Bonnett. We -- in response to your question about the human performance and fitness for duty type of situations, thinking operators, if there was a sleeping operator situation that was found, we could assess that in the performance deficiency.

That performance deficiency, if it went to an

SDP situation, would be looked at under the SPAR-H model looking at human error probability. Now, that by itself would probably come out to be of very low significance because an operator sleeping, one operator sleeping -- if you have a whole control room sleeping, you've got a different issue.

DR. APOSTOLAKIS: But that's the whole issue, it seems to me.

MR. BONNETT: We have a Peach Bottom issue where everybody's asleep in the control room, that would -- we would go first of all into our 612 appendix B, which -- where we identify the performance deficiency, then ask does this fall under traditional enforcement. If it goes under traditional enforcement, it will go over and look at the actual consequences, potential consequences, if it was willful, or it impeded the regulatory process.

At that point, once we looked at the violation, we could do the significance determination to find out what the safety significance of that violation was, and then tag a color significance to that violation.

DR. APOSTOLAKIS: So traditional enforcement takes precedence over the matrix.

MR. BONNETT: Yes. Yes. As you would go down the list, we do the tradition, then we go down to find out whether or not it goes through the SDP.

MS. SMITH: But it -- okay.

DR. MALLETT: Traditional enforcement does not take precedence. It -- there are two pathways. Some of the pathways in the reactor oversight process do not have a significance determination process connected with them. And so we handle those by the traditional method of enforcement, which has a scale of examples in it that were based on safety significance at one point in time.

DR. APOSTOLAKIS: No, but you have --

DR. MALLETT: But it's not that one takes precedence over the other.

DR. APOSTOLAKIS: But you --

DR. MALLETT: It's just another way of --

MR. MAYNARD: Well, everything gets dealt with in both systems.

DR. MALLETT: Right.

MR. MAYNARD: Every finding has to be dealt with in the traditional system as far as is it -- what's the significance of it and, you know --

DR. MALLETT: Well, we've created these terms. These terms that we've created are the reactor oversight process, we went down the path of significance determination, evaluations of findings. But some findings either don't lend themselves to that, and we haven't developed a technique for that, so we have said, okay, in those cases we will handle those by the old way; we used to do finding evaluations, and we call that tradition.

It's not that everything's held that way; it's just if you don't have an SDP for evaluating it, you go the other route. And in this case of operator licensees sleeping in the control room, there's no SDP evaluation in the ROP, so you go this other way of evaluating that.

DR. APOSTOLAKIS: But you could --

DR. MALLETT: Yes, you could.

MR. GODY: Yes, can I build on that just a little bit? If we were to deal with an operator licensing issue, and it was an individual and it was truly an individual case, we would deal with it as an individual case under the enforcement policy.

We did have one licensee in this region that had a series of fitness-for-duty events at their facility. And we processed each one of those fitness-for-duty issues with -- individually by operators. But at a certain point it triggered some concern on our part that there might be some programmatic issues, so we wrote them a letter and asked them to describe it.

Now, ultimately we determined that they didn't have a programmatic issue. But had they -- had we determined that they had a programmatic issue, then we would have dealt with that within the confines of the reactor oversight process and significance determination process.

And we have had some examples where we have had individual operator issues that we've attributed to the licensee because it was a programmatic licensee issue.

DR. MALLETT: Let me add to that. What happens then is during the mid-cycle or the end of cycle assessment that we talked about earlier, we'll talk about those -- Tony and his staff come to that and we'll talk about what operator, or examiner issues they found, or issues during the re-qual inspections, and how does that factor into the reactor oversight process.

But we may use that as an example to say, well, we think we have a substantive cross-cutting issue, here's another example of that. If that makes sense.

MS. SMITH: Yes. So you just --

DR. APOSTOLAKIS: But --

MS. SMITH: I'm sorry. Well, you just -- what they've been describing is you've got the finding, you disposition it in enforcement and significance space, then you end up with a finding you know is greater than green. And then you can look at that finding to see whether it is a contributing cause -- it was a contributing cause to it, whether it was a cross-cutting aspect.

And then that could add to your theme. Maybe you've had worker practice problems in maintenance and operations. Together those make a theme.

DR. APOSTOLAKIS: I guess my -- what's not clear to me is do all findings go to the action matrix?

MS. SMITH: Yes. Once they're -- if they're finding a performance -- if they turn out to be a performance deficiency, then they would be evaluated to what you would do with an action matrix. If they're green, it doesn't really tell you to do anything.

DR. APOSTOLAKIS: No, no, no, put more important things like -- but certain things, like operator performance, there are special rules about those things.

MS. SMITH: Right.

DR. APOSTOLAKIS: So I have now -- I can do an SDP and say, you know, that this guy was sleeping, how does that affect CDF. At the same time, I have the requirements which tell me that, boy, this guy's not supposed to be sleeping, so you've got, you know, to penalize in some way.

So I really don't -- do I need to do an SDP in that case, if there is already a regulation?

MR. BONNETT: Let me add something to that.

DR. APOSTOLAKIS: Yes.

MR. BONNETT: If there was a sleeping operator or an inattentive operator, what would happen -- what we do is we would look to see if there was performance deficiency. Was there a condition that was created that would have led to a core damage situation.

At that point we would assess the performance deficiency. In that performance deficiency we would look to see to see what kind of causal factor there was in that finding, which, in this case, it was a sleeping operator, if he was in direct correlation, that would have come in as a cross-cutting issue.

If there was greater than three number of common theme cross-cutting issues, that would to in to be assessed under the safety culture, and it would come out in that sort of assessment.

As we assess the performance deficiency, one of the things that we look at in that is the human performance area, which drilled way down in that assessment is fitness for duty, and that's part of the human error probability. But that's only one of eight criteria that we look at in that SPAR-H model.

MR. MAYNARD: What I'd like to suggest, we have some time at the end for roundtable discussion, opened up to anything. We are falling further behind. I'd like to go ahead and suggest we move ahead and then maybe come back and have some roundtable discussion.

MS. SMITH: Well, you had mentioned that you were interested in, when they use safety culture, there's -- the ways that the program now allows us to ask for the licensees to do safety-culture assessments that are new.

DR. APOSTOLAKIS: That's right. That's what I asked --

MALE VOICE: What?

MS. SMITH: Pardon?

DR. APOSTOLAKIS: Yes, that's what I asked before.

MS. SMITH: Yes. Okay. And there they are.

And then the biggest challenge for this -- in implementing this program is complex terminology because you just have to say "aspect" the right time and "area" the right time or you get confused, and that has happened at the inspection staff level, too, and so we have to work hard to overcome that.

DR. APOSTOLAKIS: Well, again -- I'm sorry, Otto, but these things about culture are there to help the agency and the licensee identify root causes that are organizationally related or human related, but they are not things that go into the matrix. The matrix looks only at the performance.

MS. SMITH: Significance.

DR. APOSTOLAKIS: Significance.

MS. SMITH: Yes.

DR. APOSTOLAKIS: But -- and there has to be a real finding, some condition for you to go to the matrix.

MS. SMITH: Yes.

DR. APOSTOLAKIS: The fact that they didn't have enough stuff doesn't go to the matrix; is possibly one of the root causes that created the finding. Is that correct?

MS. SMITH: It is correct.

DR. APOSTOLAKIS: That makes is much clearer in my mind now.

MS. SMITH: Yes, the only slight --

DR. APOSTOLAKIS: It should have been clear before --

MS. SMITH: -- variation is the cross-cutting --

DR. APOSTOLAKIS: -- I think.

MS. SMITH: -- aspect also could start from a performance deficiency, but it's about causes.

DR. APOSTOLAKIS: It's causes.

MS. SMITH: The matrix is about significance.

DR. APOSTOLAKIS: Performance. It's performance, the safety assessment.

MS. SMITH: Significance.

DR. APOSTOLAKIS: Yes --

MS. SMITH: Yes.

DR. APOSTOLAKIS: -- significance.

DR. MALLETT: In order to move on, when we get to the roundtable, we have an example that occurred here, and we can mention this because it's a public -- at the River Bend Station, it was an operator, and we can go through that. That might help you as an example, how that played out.

DR. APOSTOLAKIS: Thank you. Good.

MS. SMITH: But then -- and this is towards the end -- because of it being a hard concept to just learn to talk about and be able to exchange on, we had several training sessions, and the counterpart meetings; we've provided web-based training for anyone.

And we also -- I mentioned that increase of management oversight over the inspection finding disposition, making sure everybody was thinking everything the same thing. We had meetings to train the security community, and we hosted a regional utility group meeting, so that when you're talking to the licensee everybody was together.

And we also have kind of planned, and it's been there sort of from the beginning, that the ROP annual self-assessment report would look at this. And then another sub-tier to that is the 18-month safety-culture self-assessment group, and the routine procedure in review and upgrades, these procedures have been revised several times to clarify them.

And the manual chapter 6.12 working group, they're performing a deficiencies cross-cutting aspect audit, and two or three of these feed into the -- besides being at the regional level, they're national.

And what Roy Caniano is going to do now is to talk about the effort he's on.

DR. BONACA: I have a question on 95003.

MS. SMITH: Okay.

DR. BONACA: I mean, the way it's been developed, now it's much more precise and descriptive about what you're expecting --

MS. SMITH: Right.

DR. BONACA: -- in this evaluation. And how do you trigger this evaluation? That was the question I had before. It seems to me that --

MS. SMITH: The 95003?

DR. BONACA: Yes.

MS. SMITH: The way you trigger one of those is back over on the action matrix, if you have enough significant performance deficiencies, as those increase in significance, they have you -- and you go across the columns, and 95003 is required when you're in that last column.

MALE VOICE: Second to the last.

MS. SMITH: Second to the last.

DR. BONACA: Second to the last.

MS. SMITH: Right.

DR. BONACA: Okay.

MS. SMITH: So it's by significance. But then it goes into culture in that what it tells you to do is to evaluate -- they'll have the licensees do a safety-culture assessment.

DR. BONACA: But it seems to me that 95001 already allows now the stuff to trigger a self-assessment if there are three -- more than three known minor events --

MS. SMITH: Yes.

DR. BONACA: -- in the same category, which means before you can --

MS. SMITH: No, more than three assessment letters.

DR. BONACA: What? Yes.

MS. SMITH: I'm sorry.

DR. BONACA: An assessment of performance. Right?

MS. SMITH: Yes.

DR. BONACA: And it would expect that that assessment to performance would be similar in many ways to if a contractor would do it for the licensee. I would expect it to be very similar to 95003, because now you have specified there what you expect to see.

MS. SMITH: There would be some similarities. Do you want to talk about that --

MR. WERNER: Well, from a --

DR. APOSTOLAKIS: No, you have to --

MR. WERNER: This is Greg Werner.

MS. SMITH: He's working on the 95003.

MR. WERNER: Yes, I'm the senior projects engineer for Palo Verde. I'm familiar with the 95003. As assistant team leader of the 95003, I have responsibility for the safety-culture aspect.

So, again, it's just a graded approach, again, the ROP, so the 95001 would not have as significant of a review for safety culture as the 95003 would, because, again, that's the first starting point. So, again, as the findings become more significant, the amount of effort by both the NRC and the utilities are going to increase at each stage.

So, again, it would not be a significant -- again, the 95003 has approximately 450 hours of direct inspection that was added for safety culture alone.

DR. BONACA: The 95001 would be on the same issues, but it would be not as in depth.

MS. SMITH: Right.

MR. WERNER: Right. That is correct. Again, you have to look at the 95001 specifically, but, again, that's usually just looking at the one aspect of performance that got you in that area. So you have a cornerstone; it's not going to be nearly as in depth.

MS. SMITH: And that matches what causes it because like a white one makes a 95001, and then you've got white ones or a yellow to get to 95002, like that. So as the significance of the event or deficiency increases, you go further out on the action matrix.

And then if the safety -- substantive cross-cutting issue recurs for three times, then we can write an assessment letter to the licensee asking them to perform one of those assessments.

And that's all I have. Thank you.

MR. CANIANO: And thank you, Linda.

Again, I'm Roy Caniano. I'm the deputy director of the Division of Reactor Safety here in the Region IV office.

Earlier today, Bruce, I think in his opening remarks, mentioned that we were initiating a review of the region's implementation of cross-cutting aspects. I think also Pat mentioned this morning that, you know, the agency and the region is -- we're a learning organization.

So what prompted us to take a look at this? When you take a look at the total number of findings across the agency, and how many of those findings have cross-cutting aspects with it, there's a difference between the regions.

For example, 2006 Region IV had 218 inspection findings. Of the 218 findings, we had 179 that were tagged with a cross-cutting aspect. Now, if you compare that to some of the other regions, there's a delta. Region III, for example, has 242 findings with 116 cross-cutting aspects associated with it. In Region II we had a 136 findings with 68 cross-cutting aspects. Region I you had 182 findings with 143.

DR. APOSTOLAKIS: You have X with Y relating to components. That's what you mean.

MR. CANIANO: Yes.

DR. APOSTOLAKIS: Okay.

MR. CANIANO: Yes.

DR. APOSTOLAKIS: So you're not talking about the number of aspects?

MR. CANIANO: Yes. We looked at it and we said, you know, why is that. So we decided on a initiative that we were going to initiate a cross-cutting task group, which I'm leading. We kicked it off about three months ago.

The whole purpose is to identify the differences and/or similarities among the regions, how we implement 03.05 which is the guidance documents, et cetera for cross-cutting aspects. We're very fortunate because we've got numbers from each of the regions. I represent Region IV. We also have the office of enforcement, as well as NRR represented on this task group.

Now, early phase of this, we found that there were two other task groups that are out there that are reviewing inspection reports, 06.12, which is the format for inspection reports, there's a task group that's reviewing inspection reports to make sure that the reports are consistent with the requirements of 06.12.

At the same time there's a problem identification and resolution task group that also is looking at inspection reports. What we did not want to do is duplicate their efforts. So we got with those two groups and we basically discussed with them what do we want out of this task group.

And they are looking at about 60 plus inspection reports throughout all of the regions. We go back to about the October time frame, we're looking at the resident inspector inspection reports, and we're looking also at the division of reactor safety inspection reports, which, of course, has the regional based inspection reports.

We're also taking a look at statistics. The statistics I have you earlier were some of the NRC statistics. Last week I had the opportunity to participate in the annual American Nuclear Society meeting, and I had an opportunity to talk to them about our task group.

And I solicited input from them as well, you know, what type of data do you have that are out -- that's out there, and do you have any specific concerns with the way that the agency is implementing cross-cutting aspects. And actually at the end of September they've invited me to participate in another forum to where they're going to be able to communicate with me any specific findings that they have.

In addition to that, what we're also doing is we're participating, the task group members, in the mid-cycle reviews and in the inspection de-briefs. We mentioned earlier that Region IV had their mid-cycle reviews last week. We actually had the task group member from Region I participate in that effort.

Again, to get a sense what type of questions are we asking when a finding is identified. We want to make sure that we're consistent when their questioning the attitude, as well as the guidance in 03.05, how do you tab a finding with the cross-cutting aspect.

Tomorrow I'm going to be involved, in fact, in Region I mid-cycle. And, again, to get an assessment of how that region does it. Region III is going to be going to Region II and vice versa, Region II going to Region III. In addition to that, we're also talking to the inspectors, we're talking to the supervisors, and, again, hat's to get a sense on how are the regions implementing the cross-cutting aspects.

Our goal is to have this completed by the end of this calendar year. A big reason for that is we wanted some changes that are going to be necessary. We want to make sure that we can get them in before the next inspection cycle.

So it's a rather large effort, and, again, I think by involving and seeking input from utilities, I think is going to be very valuable. Again, by the end of September I'm hoping that I can get some useful information from them.

MR. MAYNARD: Okay. Appreciate it.

MR. CANIANO: Okay.

MR. MAYNARD: Thank you very much. I think next on our agenda, component design basis inspections, and I believe that's George Replogle.

MR. GODY: Yes, sir. Let me introduce George Replogle. He's a senior project engineer in the Division of Reactor Projects, and he will be talking about our component design basis inspection program.

MR. REPLOGLE: How are you all doing? I'm George; I'm a public servant. I'm glad to be able to sit here and talk with you today.

To be honest, I'm not really involved in these inspections that much anymore. I had led a few, but when the other folks found out you were coming, they took trips out of town. So here I am.

MR. MAYNARD: I notice you do have several slides, and --

MR. REPLOGLE: Yes, sir.

MR. MAYNARD: -- we appreciate moving through -- try to catch the key points here. I don't want to cut you short, but actually I am trying to move it along a little bit here.

MR. REPLOGLE: Yes, I will go as fast as I possibly can.

MR. MAYNARD: And I realize we're usually the speed bump.

MR. REPLOGLE: The component design basis inspections are the latest version of the NRC's team inspections. We have had some trial inspections in 2005, and these inspections have a reasonably big team, six members including the two contractors and one operations examiner.

The team spends three weeks on site. A team leader and the senior reactor analyst will also spend an additional week.

And we have a risk-informed scope. We look at 20 risk-important role margin components, five risk important operating experience issues, and that's a little bit misleading, because for the 20 components, we're going to look at over 100 operating experience reports. For the -- the five additional allows us to step outside that scope and look at other OEs. And then five risk-important operator actions.

The teams spends about a third of the allotted time just picking out what we're going to look at. And that's sort of a funny way to do things, but we believe that we're going to pay up front and we'll get dividends later. And I think it's been really working out. We've been getting a lot of fruit from our efforts, and it seems like a good way to do things for now.

Nationwide, the CDBIs in the last year and a half or so have generated 136 findings, one white finding vortexing issue at Clinton, Region III. And Region IV, out of those, has 24.

And in short my goal on these inspections was to find latent design issues. Not everything that happened at TMI was risk significant. There were a number of ducks that had to line up in a row to get to core damage, and if you could have taken one of those ducks out, even a non-risk-significant duck, and just pulled it out, you wouldn't have had core damage.

So although we're finding mostly green findings, that we're helping safety and we're taking some of those pieces out that can lead to core damage.

DR. CORRADINI: So just -- I keep on assuming, so when you say a green finding, that's something that's not of safety significance, but of concern that needs to be dealt with.

MR. REPLOGLE: That's correct.

DR. CORRADINI: Is that essentially the proper way of thinking about it?

MR. REPLOGLE: That's correct.

DR. APOSTOLAKIS: Green means two things: In performance indicators it means nothing happened.

MR. REPLOGLE: That's correct.

DR. APOSTOLAKIS: In the findings it means something has happened --

MR. REPLOGLE: So that's why --

DR. APOSTOLAKIS: -- but it has very low

significance.

DR. CORRADINI: So it's a concern, not a deficiency or a weakness.

DR. APOSTOLAKIS: Huh?

DR. CORRADINI: I view it -- I interpret it, when you say the green finding, it's something you noted, should be discussed, taken care of, but it's not of safety significance that would start adding up to --

MR. GODY: A green finding, clearly they did not implement an industry standard, or they didn't meet a requirement, so there is either a violation or they failed to implement a standard.

What we do is we assess the significance of that issue and we determine that it is of very low safety significance --

DR. CORRADINI: Therefore green.

MR. GODY: -- and that's -- and therefore green.

MR. REPLOGLE: These are greater than minor, so these are documented in reports, but we don't have additional enforcement actions that follow.

DR. APOSTOLAKIS: If an inspection finds that everything is fine, there is no color.

MR. REPLOGLE: That's correct.

MR. GODY: And green finds --

DR. APOSTOLAKIS: There is a color to --

MALE VOICE: No finding.

MR. REPLOGLE: That is correct. And all --

MALE VOICE: There's no findings.

MR. REPLOGLE: -- findings --

DR. APOSTOLAKIS: There are no findings. Yes. That's the word.

DR. BONACA: If you find a component that is not operable but it's well functional.

DR. APOSTOLAKIS: But this thing about the --

DR. CORRADINI: I don't mean to bring this up, but I just -- you were using these terms, and I know about from a performance indicator standpoint, but I just want to make sure I understand --

MALE VOICE: Wait, wait.

MR. MAYNARD: We need to -- one at a time here. Let --

MR. GODY: Yes.

MR. MAYNARD: -- Mario ask his question.

MR. GODY: There was a couple of questions here.

Dr. Bonaca, you said if it's operable but functional -- I mean, if it's not operable but functional. If it's not operable, it means it doesn't meet a tech spec requirement, and if there's a performance deficiency associated with it, then there's a finding, and we assign a significance to it.

There was another question. Any findings that are raised by inspectors, are we -- we expect them to put those issues in the corrective action program and fix.

Were there any other questions?

MR. REPLOGLE: You could have instances where equipment is inoperable and it would still be a green finding. For example, the large-break loss-of-coolant accidents, the frequency of those occurring, we believe, is so low, the equipment is only needed to mitigate a large-break loss-of-coolant accident; the risk would still be green. So you can have pretty significant issues that are still greenish.

DR. BONACA: Just in function.

MR. REPLOGLE: It could be inoperable.

DR. BONACA: But in our inoperable and non-functional is two different things. I mean, you may not meet the code, but you may determine that the component is capable of performing this function.

MR. REPLOGLE: It could be inoperable and non-functional.

DR. BONACA: Even in that case it would --

MR. REPLOGLE: But it could still be green.

DR. APOSTOLAKIS: But that I believe creates an issue of inconsistency of the policy. For events that do appear in the PRA and events that don't function, and that aren't there some findings which you cannot process through a PRA. Is that not correct?

MR. REPLOGLE: Well, there are some, but a large-break loss-of-coolant accident --

DR. APOSTOLAKIS: I understand.

MR. REPLOGLE: -- could be processed in the PRA.

DR. APOSTOLAKIS: That's absolutely --

DR. SHACK: That's typically why you find so many white findings in emergency planning.

MR. REPLOGLE: Right. That's correct.

DR. SHACK: And, you know, they're not processed through the -- because there you're sort of -- you're either -- you fail or you don't.

MR. REPLOGLE: You make it or you don't and you have a hard time assessing safety significance.

DR. SHACK: So there is a certain inconsistency there.

DR. APOSTOLAKIS: Oh, this is interesting. Can you go on?

MR. REPLOGLE: I agree.

DR. APOSTOLAKIS: Are all the findings were green, and they just lined up in green at TMI?

MR. REPLOGLE: Some of the findings at TMI were green. Some of them weren't -- aren't -- still aren't today modeled in PRAs. Most indications aren't modeled in PRAs, so reactor vessel lead -- reactor vessel level indication in the heads, that's not generally modeled in the PRAs.

So if the licensee has that inoperable for a very long period of time, it's not going to change the risk numbers. So that would be a green issue. But if we look back at TMI and say, well, if the operators really had good reactor vessel level head indication, they probably wouldn't have secured safety injection and they could have avoided core damage.

So if we find today that that indications has been inoperable, non-functional for a whole year, chances are that's going to be a green issue. But in the right context, it could be, you know, significant.

All right. Strengths, I think this inspection approach lets us look deeper into the design of the individual components. Past engineering teams have been conducted on a system-based approach, and there's only so far you can look at when you're looking at a whole system.

A real system has maybe hundreds, thousands of components when you look at all control circuits. This approach we can take a pump, take a valve, and we just inspect it all the way down to the bone.

This also helps us take a look at how the licensee's been maintaining their design, where they've had design lapses over time, because we're looking at the initial design when the plant was licensed, what the design is today, and we're comparing all the difference in between.

The challenge, it's hard to be consistent. We're human beings. It's very difficult to make every human being on this inspection perform exactly the same way. Some of our contractors are just world class; they have the best minds in the industry. Some of them are at the other extreme. The same thing with inspector skills. Licensees --

DR. SHACK: Hope they're not that bad.

MR. REPLOGLE: Some licensees will figure out pretty quickly it's not really in their best interest to support us as much as we would like. And this inspection is a pretty big drain on their resources. A lot of licensees have trouble keeping up with the team.

And then team leader skills, some team leaders can -- are better at evaluating conditions and coming up and making a pretty good regulatory case. Others are less skilled at doing that. And so we're trying to manage those, but those are real-life inconsistencies, and they affect the results.

All right. I'll give you an example of --

MR. MAYNARD: You might have to carry the microphone with you.

MR. REPLOGLE: Give you an example of a couple of findings that we've had at one plant. Here's a refueling water storage tank at Calloway. And we selected this system because it had 1 percent margin, design margin, in this case.

And the first thing I'll talk about is this instrument allowance for instrument uncertainty. Three percent instrument uncertainty. That's what this amount of volume is there to provide. And what -- we looked at the licensee's corrective action program, and they had identified, all on their own, that they hadn't accounted for vortexing.

So they did a calculation and they said, well, vortexing would take up about 2 percent of the volume, so this 3 percent for instrument uncertainty, that covers that, so we're okay. And I said, no, you need this for instrument uncertainty; you need additional to account for vortexing.

So in this case, what the licensee did is they did sensitivity evaluation of the instruments that were installed at the time, and they found that the instrument drift was really less than 1 percent, so they were only using about 1 percent of it. So in this case, the system was still operable.

DR. CORRADINI: I think I know what you mean by vortexing; you mean drawing in water when you're down at the lower extreme when you have ECCS injection?

MR. REPLOGLE: Yes, just like when you flush the toilet.

DR. CORRADINI: So let me ask, do all of these have some sort of guards to stop vortexing, or these are just open pipes?

MR. REPLOGLE: It depends. All the plants are different.

DR. CORRADINI: So in this one.

MR. REPLOGLE: This one didn't.

DR. CORRADINI: Did?

MR. REPLOGLE: Did not.

DR. CORRADINI: Did not. And what does 2 percent -- I think you said 2 percent -- what does 2 percent translate into on a length scale?

MR. REPLOGLE: Oh, in a length scale?

DR. CORRADINI: Yes, pipe.

MR. REPLOGLE: I think the 2 percent accounted for about two inches -- two to four inches, I think. It wasn't a lot.

DR. CORRADINI: Okay.

MR. REPLOGLE: So our concern is --

DR. WALLIS: Why do they have that dead volume? It just seems to be a waste to design a system with a dead volume.

MR. REPLOGLE: It's just the way -- I think it's just way it's designed, so the pipe doesn't suck in stuff.

DR. WALLIS: Yes, but do you need 12 inches to correct?

MR. REPLOGLE: Yes, this is where the top of the pipe is --

DR. WALLIS: I know, but it seems a bit odd to put it there.

MR. REPLOGLE: Yes.

DR. WALLIS: I mean, the drain from my bathtub isn't 12 inches off the bottom of the bathtub.

MR. REPLOGLE: That's true.

DR. CORRADINI: What surprises me more is the fact that they said two inches is all you need to accommodate vortexing.

MR. REPLOGLE: Okay. I'll do it. All right. Now, here's a second issue. When you have your large-break loss-of-coolant accident, six pumps take the suction off this tank and suck down all at the same time so the level starts coming down.

This vent at the top has to be designed to account for that level decrease, and it has to let in an equal amount of air as there is water going out.

Our contractor looked at the calculation for the vent and then the vent sizing calculation, which had been there since the plant was built, had only assumed that one pump started. So that was a mistake. They should have assumed that six pumps started.

DR. WALLIS: Does the tank collapse in that case?

MR. REPLOGLE: Well, it had a structural integrity value of only a few inches of water. So originally they had sized the vent -- this is a very big tank, and that vent's really much smaller than I've draw it there. Here's the actual vent. They thought they had 60 percent margin, and when pointed out this error, they said, well, we're okay because we have 5 percent margin left.

And what we said was, you know, a bird nest could cover that 5 percent. You know, how do we know there's not a bird nest or something up there? The opening's four inches; the diameter of this pipe is 16 inches.

And so they went up there and looked, and what they found was this fine mesh screen covering a vent that they had put up there for some other work and they had forgotten about it and left it up there in 2002.

Now, ice storms, they have ice storms at Calloway; that can cover over 5 percent. So they took that off, and as we were leaving the site, they had an ice storm, and so that's just-in-time inspection on our part.

But this issue, we couldn't determine that the system was operable with this vent on there with this extra mesh screen on there. So this is an instance where for a large-break loss-of-coolant accidents, when they had an ice storm, at least when they had an ice storm, this system may not have been able to perform its safety function, but it was green because of the risk.

DR. WALLIS: I would think snow would work too. I mean, if you use it in a snow storm, the snow would pack up on the screen, wouldn't it?

MR. REPLOGLE: That's true. That's true. So there is a number of things that could clog this up. And that's all I had, unless there are any additional questions.

DR. WALLIS: So what did you do about it, take off the screen?

MR. REPLOGLE: They took off the screen.

DR. MALLETT: I'd like to add I think George undersells himself and the rest of the rest of the people. These component design inspections have gotten us a lot more deeper into the design and found things at facilities that we didn't realize and they didn't realize were a problem, and they fixed them.

In almost every place they've gone they found significant design issues.

DR. WALLIS: Well, I bet that's not in the PRA.

DR. MALLETT: I don't know the answer to that, George.

DR. WALLIS: That screen isn't in --

DR. MALLETT: It probably wasn't --

DR. WALLIS: -- the PRA.

DR. MALLETT: -- in the PRA.

MR. REPLOGLE: Failure of the tank would be in the PRA, but this wouldn't be.

MR. MAYNARD: This type of inspection, it's very demanding on the NRC and on the licensee. But it is going back to things that probably haven't been looked at in many cases since the original design back in the '70s-'80s time frame when a lot of these designs were done. So there is a lot of fruit to come out of these inspections.

DR. SHACK: Was this something that found the software air problem at Palo Verde in that core calculator, or did that come out of some other inspection?

MR. WARNICK: We don't know the answer to that question. We can get back to you.

DR. MALLETT: I'm just wondering how some of these latent errors are found. I mean, they just --

MR. WARNICK: That was something identified by the --

MR. MAYNARD: They need to use a microphone.

MR. WARNICK: I'm sorry. This is Greg Warnick, senior resident. That -- they've upgraded their core protection calculators in units 1 and 2, and that was a flaw identified by the vendor.

MR. MAYNARD: What I'd like to do now, if we could, we'll take a break. We'll come back and we'll have a roundtable discussion here, and I think any of these issues that we've been talking about, to give us an opportunity to revisit any of those and to spend some more time on that.

So what I'd like to do is we'll take a break until 2:40, and we'll be back in here and then start a roundtable discussion.

(Whereupon, a short recess was taken.)

MR. MAYNARD: We'll get started. We have a couple of members out, but this is a fairly informal part of the session; it's just dialogue back and forth, and we'll discuss things.

We're back on the record. I'll turn it back over to Tony to introduce some of the folks.

MR. GODY: Thank you, sir.

What I'd like to do is introduce the members of the panel here, and I guess I'll go myself first. My name is Anthony Gody; I'm chief of the Operations Branch. I've been the chief of the Region IV Operations Branch since 2004 -- I'm sorry, 2001, and I started in Region IV in 1994 as the senior resident inspector at Comanche Peak.

I did join the NRC in 1989 as a project manager in the Office of Nuclear Reactor Regulations, and prior to the NRC I was a naval officer. Went to the University of Florida, one of the best engineering schools in the country, and --

MR. MAYNARD: Oh, that'll start some debate.

(General laughter and discussion.)

MR. GODY: And I also was an enlisted man in the Navy also as a reactor operator.

As I introduce individuals, either raise your hand or stand up. Kelly Clayton is currently a senior operations engineer in Region IV. Kelly is originally from Texas and a graduate of the University of Texas at Austin with a bachelor of science degree in chemical engineering.

DR. APOSTOLAKIS: How good is that school?

MR. GODY: That's pretty good.

DR. APOSTOLAKIS: Okay. Good.

MR. GODY: With a specialty in digital controls. Prior to joining the NRC, Kelly spent six years in the United States Navy as a load dispatcher and nuclear plant operator/supervisor. Mr. Clayton, or Kelly we call him, worked for Fisher-Rosemount [phonetic] Systems as a senior controls engineer installing and testing digital controls equipment in over 168 locations for companies such as Exxon, Georgia-Pacific, Merck and Bayer.

Kelly joined the NRC in 2002 and currently works for the Operations Branch.

MALE VOICE: Hopefully he was not dispatching nuclear loads.

MR. GODY: Okay. Paul Elkmann. Paul has a bachelor of science degree in physics from Case Western Reserve University in Cleveland, Ohio, and a master of science degree in radiation biology, University of Iowa.

He currently is an emergency preparedness inspector and he is also a reactor health physics inspector and he works in the Division of Reactor Safety, Operations Branch. And he's been with Region IV for eight and a half years. As a collateral assignment, Paul also is the Region IV dosimetrist.

Prior to joining NRC, Paul was an emergency planning specialist for Carmen Wolf Edison [phonetic] Company, health physicist for the State of Iowa public health and health physics technician for Canberra.

Greg Warnick. Greg Warnick first joined the NRC in 1997 as a project engineer in NRC Region II's office in Atlanta. In 1998 Greg was assigned as a resident inspector at the St. Lucie Nuclear Power Plant in St. Lucie, Florida.

In December of 2000, Greg transferred to Region IV, was assigned as a resident inspector of the Palo Verde Nuclear Generating Station. In 2004, Greg was promoted to the position of senior resident inspector at Palo Verde.

Prior to joining the NRC, Greg was employed as a nuclear plant engineer with Lockheed-Martin, Knolls Atomic Power Laboratory.

Greg graduated from Brigham Young University with a bachelor of science degree in mechanical engineering in 1993.

George Replogle.

MR. REPLOGLE: You can skip mine.

MR. GODY: Okay -- no. Mr. Replogle is currently senior project engineer in the Division of Reactor Projects. Previously Mr. Replogle worked as a senior engineer in the Division of Reactor Safety, and held senior resident inspector positions at Columbia

Generating Station and River Bend.

George also worked as a resident inspector at Columbia Generating Station, and served as a reactor inspector in Region III Division of Reactor Safety.

Overall George has over 20 years of government service. He has a bachelor of science degree in mechanical engineering from Sacramento State University, an associates degree in electronics technology from Orange Coast College. Mr. Replogle has also completed graduate level work towards a master's degree in business administration.

MR. MAYNARD: Did he work at Columbia Generating Station as an employee, and then also was there as a resident inspector, or did I get --

MR. REPLOGLE: No, I was a resident inspector, and then I went to River Bend to be a senior, and then I came back as a senior resident inspector.

MR. MAYNARD: So you -- okay.

MR. GODY: So he held both the resident and senior positions.

MR. MAYNARD: Okay.

MR. GODY: Dave Loveless. Dave Loveless currently is a senior reactor analyst in the Division of Reactor Safety, and he's been in that position for about six years. Major positions in the past: He was senior resident inspector at South Texas project, resident inspector at River Bend and Sequoyah.

He also worked at the Accident and Evaluation Branch in the Office of Nuclear Reactor Regulations, and he worked for the licensee as a nuclear engineer at Calvert Cliffs Nuclear Power Plant.

He has a bachelor of science degree in nuclear engineering from Rensselaer Polytechnic Institute. That's why they're small letters. He completed the senior reactor analyst certification program, the resident inspector certification program, and he currently has -- also has a nuclear technology certificate from Chattanooga State College.

Jim Drake. Jim is currently an operations engineer in Operations Branch. He served in the United States Navy prior to the NRC as a junior officer, combat systems officer, engineer, and squadron engineer in the Mediterranean and as an intelligence office with NATO.

He qualified chief examiner, emergency planning inspector, and reactor inspector while he's been at the NRC.

He also enlisted in the United States Navy in 1977 as an interior communication technician. He attended the D-1 G and the MARV prototypes. And he has a bachelor of science degree in electrical engineering from the Naval

Academy, and a master of science degree in systems technology from the Naval Post-Graduate School.

Paul Bonnett. Paul Bonnett received his initial training from Naval Nuclear Power School in 1973. He graduated from Thomas Edison State College in 1990 with a bachelor of science degree in nuclear engineering technology.

In 1983 he went to work for Public Service Electric and Gas Company and licensed as a nuclear control operator at Hope Creek Generating Station, which was currently under construction at the time.

In June of 1986 Paul formed the Initial Criticality Historical Unit. He joined NRC at Region I in September of 1988 as a licensed examiner. He certified as an inspector and became a senior operations engineer.

He assisted in the Operator License Branch at headquarters in developing guidance for senior reactor operator limited to fuel handling series in the examination standard -- and we need to talk about that.

He was the chief examiner on the pilot exam at Limerick Generating Station, and between 1992 and 2000, Paul was a resident inspector at Peach Bottom Station, and then Limerick Station. And he was assigned to the Region I Tech Support Organization in 2000.

In August of 2003 Paul became the program analyst in the Office of Regional Administrator providing inputs for the annual regional operating, metrics and budget.

In January of 2004 Paul joined the Inspection Program Branch, now the Reactor Inspection Branch in the Office of Nuclear Regulation, and managed the ROP feedback process and several inspection procedures.

He was recently promoted to senior reactor analyst and completed a certification. He is currently the program lead for the Significance Determination Process.

John Hanna. John Hanna's currently the senior resident inspector at Ft. Calhoun. He joined the NRC Region IV in 1997 as a reactor inspector in Branch Bravo of the Division of Reactor Projects. He has also been the resident inspector at ANO, Calloway, acting senior resident at River Bend and Turkey Point.

John attended Georgia Tech specializing in bio-engineering and graduated in 1990. Immediately following college he started working for the Navy as a ship test engineer, and he did some work on fast attack submarines and a great deal of work on cruiser refuelings and decommissionings, and was cross-qualifying to carriers when he came to work for the NRC.

John lives in Omaha, Nebraska with his wife

Heather.

MR. MAYNARD: That's a good thing, because that's where Ft. Calhoun is. It'd be a long drive every day if he lived here.

MR. HANNA: It makes it a little bit easier to get to work, yes.

MR. MAYNARD: Okay. If that's the introductions, what I'd like to do is, again, kind of open up for anything that we've discussed today, and really anything else is fair game too we could talk about.

I'd like to start off with George and see -- I kind of cut you off a while ago -- and to see if you've got your questions answered, or if you want to pursue that anymore.

DR. APOSTOLAKIS: I think we have a response to the issue of operators sleeping.

MR. WARNICK: Yes, actually Tony was going to get an answer to that --

DR. APOSTOLAKIS: Okay.

MR. WARNICK: -- on how it's going to be handled through the ROP.

MR. GODY: Okay. I didn't think I was going to start right off the bat. Okay. The question earlier was surrounding whether or not we would deal with an operator issue in the SDP, and the question is -- has to do with how would we deal with an operator -- human performance type issue in the SDP.

Well, there's -- we can do this through a number of different examples, but at one facility -- and I'm going to avoid plant names, even though it's public material -- at one facility an operator was removing a strip chart recorder and in the process of doing that dropped it, and it resulted in a plant transient.

We evaluated the fact that he had that -- what -- did not provide -- or do adequate self-checking and peer checking, and adequate attention to detail when he was removing that strip chart recorder, and we identified that there was a transient associated with that, and the performance deficiency resulted in some type of plant impact.

So what we did was we assessed the plant impact and assigned the risk of that issue, the risk determination from that issue, based on the plant impact.

Is there anybody else in here that knows this detail, this issue, better than that?

MR. LOVELESS: I was the team -- I'm David Loveless. I was the team leader for the special inspection, and Jim here was also on that team.

From a -- how it worked in the program, we identified a number of performance deficiencies during that inspection. The one in particular with how the operator handled the chart recorder was also tied back to some other issues that the -- where the licensee had had problems working over panels, but --

MR. MAYNARD: To clarify, I'm assuming that by dropping -- he dropped it on something on the control panel that caused the --

MR. LOVELESS: Yes, it dropped on the control panel. It actuated isolation of the feed water system and caused a reactor scram as a result.

The -- but once we identified the performance deficiencies associated with that event, and some of the surrounding issues, we take those, each of those issues, we look at -- then we put them into the significance determination process.

We then process each individual performance deficiency in an isolated case within its cornerstone. And in this case all of the findings that we had were green, and based on specific risk associated with any given performance deficiency.

Now, the total risk associated with the event was higher, but our significance determination process looks at just those individual actions where the licensee made an error, or where they had a performance deficiency.

MR. WARNICK: Can you remember what -- how much the risk was from this event?

MR. LOVELESS: We only did a preliminary on that, but it was in between a 10^{-6} and 10^{-5} per reactor year, core damage frequency associated with the event.

DR. APOSTOLAKIS: But I guess I don't quite understand this. There was a transient. Right? What is the performance deficiency in this case? I mean, what is it that goes into the SDP?

MR. LOVELESS: Okay. Well, one of the rules that came up very early on, and has followed through in the ROP is that we do -- will not evaluate an event under the SDP. So the fact that there was an event, we don't look at the conditional core damage probability of that event and apply it to the licensing performance deficiency.

So what we have to look at is this operator made an error, we saw other operator errors that were similar to this, we had a control panel that was unprotected. So we looked at over a time frame what's the probability that this would occur, even though we know it occurred that one time, what's the frequency with which that kind of error occurs. And then we looked at the risk of the --

DR. APOSTOLAKIS: Are you looking at the individual? In other words you are looking at the significance of the panel being unprotected and then you look at the significance of the error. Or do you consider the error plus the fact that it's unprotected?

MR. LOVELESS: We only look at single human -- or single licensee performance deficiencies. And so if a licensee performance deficiency is seen as -- a single performance deficiency is seen in a number of problems, then all of those problems would be assessed for significance together to look at the risk of that performance deficiency.

But if you have a single performance deficiency isolated from any other, then we would look at the risk just of that --

DR. APOSTOLAKIS: Not about this --

MR. LOVELESS: -- particular --

DR. APOSTOLAKIS: -- time. Do you look at all the things he might have dropped it on, or something like that? I mean, there's a whole spectrum of things if you start looking at dropping things on the control panel.

MR. LOVELESS: Well, I understand, and I was trying to avoid getting into the actual risk analysis aspects of it in this particular case.

MS. BANERJEE: No, David, give him an example of one of the performance deficiencies. He dropped it, he didn't look right away and see what --

MR. LOVELESS: Yes, that was -- one of the performance deficiencies was that he dropped it, scooped it up, took a quick look around and took it over to fix it. And a second performance deficiency that was related to that was the two senior operators walked by that panel between the time he dropped it --

DR. APOSTOLAKIS: Meanwhile there's no feed water --

MR. LOVELESS: -- and the time that the reactor scrammed, feed water is isolating and none of these operators recognized that feed water was isolated. So those -- that -- those are two different performance deficiencies that we would evaluate.

Now, both of those performance deficiencies would be very low in risk because the time frames associated with it, it was only a couple of minute window, and so that risk would be very low. Now, the --

DR. APOSTOLAKIS: Couldn't you restore feed water before the reactor scrammed?

MR. LOVELESS: We looked at it. We believe that they could have restored in this particular case.

DR. APOSTOLAKIS: And, again, you say you look at them in isolation, so they'd been noticed, because it was the feed water system had stopped. Correct?

MR. LOVELESS: Correct.

DR. APOSTOLAKIS: Are you now evaluating -- are you --

VOICE: Oh, I'm sorry.

DR. APOSTOLAKIS: -- are you evaluating --

MR. LOVELESS: No, no, I misunderstood what you said. You said that the --

DR. APOSTOLAKIS: What did -- the senior operators walked by, what is it that they did not notice?

MR. LOVELESS: The only thing on the panel at the specific time would have been that two push buttons that were in the full open position were now popped to where they would have been at a neutral position, indicating that the valves weren't in their proper position.

DR. APOSTOLAKIS: Okay. But there were some enunciators. Right?

MR. LOVELESS: They had not gotten enunciators at that point, and there were some indication problems, so it got much more complicated than that, but there were indications that were difficult to detect, but given that somebody had just dropped a heavy piece of equipment on top of the control panel --

DR. APOSTOLAKIS: And they knew that --

MR. LOVELESS: -- we would have expected that operators would have looked at things.

DR. APOSTOLAKIS: And they knew that, they knew that somebody had dropped --

MR. LOVELESS: Oh, everybody in the control room knew --

DR. APOSTOLAKIS: But when you do --

MR. LOVELESS: -- that it dropped.

DR. APOSTOLAKIS: -- when you do the SDP, are you evaluating or determining the significance of this specific incident or deficiency, or are you assuming that they never noticed about those being out of place and so on?

MR. LOVELESS: Well --

DR. APOSTOLAKIS: The reason why I'm asking is because in PRA, the more you go down to the causes and the details, the less significant these events become. So do we have an inherent problem here where we're looking at something so detailed that we know in advance the CDF change will be insignificant?

MR. LOVELESS: Under our program, we do have a number of personnel actions that, because of their nature, will not show up as significant performance deficiencies. We look at those in a number of different ways.

If we have common thread performance deficiencies where we know that the training was wrong and that they're not doing a set item -- they're not doing something they're supposed to and they're always not doing what they're supposed to, then we can look at that using our probabilistic tools and determine what the risk of that broader performance deficiency is.

But, yes, our -- as an analyst, my job is to look at the performance deficiency as scoped by the inspectors in the field.

DR. ABDEL-KAHLIK: So when you say that the estimated core damage frequency associated with that 10^{-5} to 10^{-6}, you were talking about evaluating this inadvertent feed water isolation event by itself, or are you evaluating other events that could have potentially happened from dropping something on an unprotected panel in general?

MR. LOVELESS: That was the conditional core damage probability of the event that occurred. We -- not in the SDP, in our what we call management directive 8.3, when we decide whether we want to have a reactive inspection for something that's occurred, we look at, given the initiator that occurred, but assuming that a random probability of components and equipment failing beyond that initiating time, what's the probability that it would go to core damage very similar to what an ASP would look at.

DR. ABDEL-KAHLIK: The initiating event is someone dropped something. Right? I mean, this thing could have dropped on the edge of the panel, touched nothing, and would have had no impact. But still, it is a significant event in and of itself, so how would you assign a core damage probability or a significance to an event of that type?

MR. LOVELESS: Okay. In that particular circumstance, what we evaluated was -- we evaluate at what we call an initiator, which is a transient reactor scram, a loss of offsite power, a loss of --

VOICE: A loss of normal --

MR. LOVELESS: -- coolant, those sort of things. So the time zero that we would have started with as our initiator would have been the reactor scram on loss of feed water. It wouldn't -- we wouldn't have analyzed given somebody dropped something on the panel, what's the probability that that goes on.

Now, we do some of that type of analysis when we're looking at the SDP for the performance deficiency. But when we're assessing the risk of an event, we start with the actual demand for the rods to go in the reactor.

DR. APOSTOLAKIS: But I thought you said earlier that you will not do an ASP kind of analysis.

MR. LOVELESS: That assessment is not an SDP --

DR. APOSTOLAKIS: ASP. And I was -- you said that before, you said that --

MR. LOVELESS: Yes.

DR. APOSTOLAKIS: -- the fact that you had a transient is not something you analyze. You're looking for deficiencies and you're analyzing deficiencies.

MR. LOVELESS: We don't analyze it under the significance determination process in order to look at where we fall in the action matrix. As an analyst, I do analyze pretty much every reactor scram and many significant degraded conditions, and I look at the total risk of that.

And that total risk helps us determine whether we're going to do reactive inspections, special inspections, augmented inspections.

DR. APOSTOLAKIS: But that doesn't go into the action matrix?

MR. LOVELESS: The risk of the --

DR. APOSTOLAKIS: Oh.

MR. LOVELESS: -- event that we look at initially does not go in the action matrix, because that may or may not have been related to a performance deficiency.

DR. APOSTOLAKIS: So that several issues, you have an event, you analyze it outside the action matrix, and you get a condition for damage probability, you declare whether you want to have additional inspections. Now, that event, you look at it more carefully, and you say, well, there were three causes that contributed to it, like he dropped it, and so on.

Then you have make a determination whether each of these contributing events, sub-events, is a deficiency or not, because things do happen at random too, I mean. So that's a first judgment. Then you decide that each one was indeed a deficiency, that each one would be put in an SDP calculation independently of the other two.

MR. LOVELESS: That's correct.

DR. APOSTOLAKIS: And then my suspicion is that by doing that, you are bound to get very low probabilities.

MR. LOVELESS: And at times that's true.

DR. APOSTOLAKIS: Well, even today. Because these are very little things. I mean it's -- when you have the compound event, that's bigger problem.

MR. LOVELESS: Let me give you one good example. It would be a loss of offsite power. If a transmission grid, may not even be the same operator that owns the reactor, has a loss of major lines coming into the plant, and that loss of power to the plant causes them to lose all offsite power, they trip, they go on their emergency offsite power.

That's a very significant event, but that may not -- in that event, there may not be any performance deficiency related to licensee performance. So -- but there's a very high risk peak. And in the SDP itself and the action matrix, we're trying to assess how well is the licensee performing, and the licensee's performance wasn't degraded; it wasn't indicative that they were degraded.

In fact, if there are no performance deficiencies from that loss of offsite power, it may be indicative that they're doing very well, that they're able to handle that type of transient.

So we get the -- we have two different metrics. One is the risk associated with the event that occurred, and that tells us do we need to spend our time to look at it, and the other is what's the risk of the performance deficiencies when the licensees make mistakes.

DR. APOSTOLAKIS: That brings to mind what happened in Sweden; I think it was Ostershom [phonetic] or one of those, where there was a loss of offsite power, and as I recall they had four diesels, and two failed to stop. Now, following the logic you just described, the loss of offsite power and the whole respons~~ibility~~e of the facility that's something you will look into, but it's not part of the SDP.

However, the fact that two diesels did not stop out of the four makes you suspicious and you look into that occurrence trying to see whether there is a performance deficiency that led to that --

MR. LOVELESS: Absolutely.

DR. APOSTOLAKIS: -- and if you find a performance deficiency that is common to both diesels, then you process that deficiency through the SDP. Is that correct?

MR. LOVELESS: Absolutely.

DR. APOSTOLAKIS: And you will assume in the way that that deficiency perhaps could have failed all four with some probability. Is that correct?

VOICE: Yes.

MR. LOVELESS: Yes.

VOICE: He's absolutely correct.

MR. LOVELESS: We've actually had that before --

DR. APOSTOLAKIS: Yes, and then you --

MR. LOVELESS: -- in Palo Verde.

MR. GODY: Yes, I was going to say the Palo Verde loss of offsite power event, the event itself was significant. They lost a considerable amount of generation. There was a momentary blackout in Phoenix, a significant emotional event for that area.

But when we did -- I was actually the leader of that augmented inspection team, and we determined that it met the criteria for having a team immediately go out and assess the event. When we were done we had over 15 findings from that event, 15 or so performance deficiencies of the facility. One of them involved decreasing the reliability of some of the offsite lines.

So what we do is we'll go out and we'll send a team of inspectors out based on the risk, or the significance of the event that's determined by the senior reactor analyst, and we'll assess performance. And each one of those performance deficiencies that's identified will be assessed as a standalone issue.

DR. ABDEL-KAHLIK: Let me just ask about the other end, the other extreme of this scenario. Let's say the operator dropped this chart recorder on the edge of a panel, nothing happened. Would you have heard about it?

MR. LOVELESS: It's quite possible we would have heard about it, because we have the resident inspectors on site. It's also possible that we wouldn't have heard about it. In our better performing plants we would see trending where they would be looking at operator errors at that level. Some of our plants we might not see --

DR. BONACA: Would the licensee report the condition if nothing -- if there was no consequence?

MR. BONNETT: It's possible that if he dropped the chart recorder and nothing occurred, and the licensee was -- had a low threshold for putting things in their corrective action system, that would have been entered into that.

Had we heard about it in a morning meeting or something like that, gone and looked into it, we would have found that they've already identified it, put it in their corrective action system, and then we wouldn't ~~we~~ follow up on it after that since they've already taken actions towards that. It would be more or less licensee identified.

Had they not done that, and we brought that back and we brought it to the SRAs to do an assessment about that, it could turn out to be a finding because the -- it was a performance that wasn't captured or looked at by the licensee.

DR. BONACA: It could still be a defective control room design, for example, okay, that leads the operator to drop --

VOICE: Right.

DR. BONACA: -- this --

MR. BONNETT: Well, I think that's a -- most control room designs are going --

DR. BONACA: Well, that's what I'm saying.

That's why it --

MR. BONNETT: Right.

DR. BONACA: -- would go in the corrective action system, because you want to evaluate to make sure that if there is, in fact, a design deficiency --

MR. BONNETT: Sure.

DR. BONACA: -- that you have a frequent operation, for example, that may lead you to drop this on the console.

MR. BONNETT: And that would give us an indication of the health of their corrective action process.

MR. GODY: Exactly. There may be some kind of detent on the device that would prevent it from falling out of its rack, and that detent could have been degraded or broken, and -- which it was in this case, and we would expect them to put it in their corrective action program because it is a condition adverse to quality, and that's required by 10 C.F.R. Part 50, Appendix B, Criterion 16.

DR. ABDEL-KAHLIK: But that's where my concern about the mechanics of the process comes from. In a sense that -- regardless of what the consequence of the initial event, which is dropping of something on the console is, whether the isolated feed water or initiated high pressure safety injection, whatever the outcome, these are all caused, or potentially were caused by the same thing.

And when you say the analysis starts by looking at the event itself rather than what caused the event, then I'm not sure what's the value of this process.

MR. LOVELESS: Remember we were talking about two different processes. One is our process to determine if there's a -- if we need to have a reactive inspection, send out additional resources beyond the resident inspectors to take a look at the event. That's the analysis that I was talking about that starts with the event and says, okay, the event occurred, what's the risk of having that event tomorrow, the same event.

When we did analyze this specific evaluation, we went all the way back -- we went back well before the actual event. We looked at other events where they dropped things on the panels and how they handled it. And we looked at operator training in these areas, and we looked at failures of the same mechanism that failed in the recorders.

VOICE: Operator experience at other plants.

MR. LOVELESS: Yes, we pulled in operator experience from other plants, that sort of thing.

MR. WARNICK: I'd just like to say something. This is Greg Warnick, senior resident at Palo Verde.

It really gets to the threshold that the licensee has in the corrective action program as it was stated earlier. An interesting example that I'd like to share of Palo Verde, just weeks after this event happened at this facility -- you know, the rest of the industry were aware of it, there are daily reports that go out about a reactor plant tripping off.

Well, it was us inspectors that were walking through the control room and noticed that they had the -- had several of their instruments pulled out from the panel, and they were just sitting in the withdrawn position.

We walked in there and asked why are those instruments withdrawn, is that okay? Well, they stated to us, well, that's what we always do. If the paper's running out we pull it out so we can see when the paper's out, we leave it there for a few hours, and at that point, when we see it's pulled out, we'll change the paper.

Well, we asked if that was all right in light of what just happened at this other facility with an instrument falling on the panel and causing a reactor trip. Well, they said they didn't know if that was wrong, but that's how they'd always done it.

Well, as they looked into it, it turns out in this withdrawn position they were not seismically qualified. So it was a poor -- that's an example of a facility that didn't have a good threshold, they knew about this other example that happened of something falling.

But they failed to ask themselves what could that mean to us? Is this practice that we use, could that cause a problem with us? You asked if we, the residents, would find out about it if they dropped something and it didn't affect anything.

Well, it depends on the threshold that the licensee has. If the individuals who dropped it and nothing happened stop and question themselves, hey, what if that fell on this button, or what if this fell somewhere else, what could have happened? If they have a good questioning attitude, a good threshold, they'd put that in their corrective action program to do something about it.

What we saw at Palo Verde is they didn't question themselves on that. They didn't have a good threshold. It took the inspectors, on our daily observations, to go in and say, hey, in light of what happened, you know, that just doesn't look right. Why is that okay?

VOICE: And, Greg --

DR. APOSTOLAKIS: Wouldn't that depend on an SDP? You would find a very low probability -- right? --

because the earthquake must occur first, which is fairly --

MR. WARNICK: That's correct, but --

DR. APOSTOLAKIS: -- everything has to follow this --

MR. WARNICK: That's right. But it's important for us to go out and identify these things so that it doesn't lead to a more significant issue.

DR. APOSTOLAKIS: Not about this. Just the SDP that's --

MR. GODY: And Greg's got a good point here. If you actually were to look at some of the findings that we have in our region, there's numerous examples where the inspectors have identified findings at one utility and then go out to another utility and find the same findings.

For example, in the emergency preparedness area we found that at one facility the licensee was not adequately tracking equipment that they rely on in their emergency plan when it was out of service, and -- but this particular facility was seismic monitors, and it was in California.

And they had EILs that were driven directly off of that seismic monitor and had been out of service a lot. So we actually raised that as an industry issue, and I don't know, Paul, if you wanted to talk a little bit about that or not, but we found issues in other facilities that --

DR. APOSTOLAKIS: So the natural conclusion from that then, the first conclusion, is that they should improve the way of learning from the experience of other facilities. Right?

DR. BONACA: One thing I wanted to say, assuming that dropping this component on the console -- I'll give you three scenarios, one is that nothing happens because he's on one side and so a guy gets lucky. At the most they may have some entry to the corrective action program.

Second scenario, we have a scram, as they did; nothing much happens, but, you know, they get the green maybe. In the third one, they have a transient that leads very close to core damage. It doesn't go to core damage, but it's -- in that case this operator may get, you know, a white or a red. Okay.

So I'm saying at times I really wonder too, I mean, depending on how lucky he is, you know, he ends up with a very different outcome from the regulatory oversight process.

MR. WARNICK: Well, carrying that on a little bit more, with the Palo Verde issue that we found where they didn't learn from the mistakes of others, they didn't recognize at a good threshold what the significance of their practice was. We did issue a finding; sure, it was a green significance; there was no seismic event involved.

However, we did see that there was a PIR cross-cutting aspect about that. They failed to learn from other facilities, they failed to have a good threshold, and those cross-cutting aspects roll up into our assessment.

At Palo Verde we say that they have a substantive cross-cutting issue in PIR. That means that, we believe, through our assessment process, that they don't have a good threshold.

So because of that, they have to take actions to correct that threshold so that in the future, as we continue to inspect through and they correct their problems, they'll get to the point where it's not us saying, hey, why is that instrument withdrawn, but they'll use the OE program, say, hey, look, this happened somewhere else, what does that mean to us, and they can fix those problems themselves.

MR. GODY: Right. And then, Dr. Bonaca, the -- what it would mean is that the licensee that had the instrument bounce off the control panel and there was no event may not get any additional inspection. The licensee that had this device hit the panel and they had a significant plant event may get an augmented inspection team which might have eight or ten people on it.

So assessing the significance of the event determines our response to the licensee.

DR. BONACA: Yes, I just -- the reason there's an issue in the sense that -- assumed that this was, in fact, caused by deficiency in design of this panel, that you had a routine performance, something that the operator has to repeatedly do every few days or weeks, and every time it brings you close to an event, because it's hard to reach or something. Okay.

So therefore you -- the same deficiency, however, my come in a very different regulatory outcome depending on how lucky the guy is, I mean, whether it hits the panel. And it seems to me that the -- maybe that's -- I don't know.

MR. HANNA: One thing, if I could add on to what Tony was saying. We have talked about the how we go about determining whether a supplemental inspection would be done, and a lot of the discussion thus far has involved risk numbers and E to the minus five, six, whatever.

There's -- what we haven't talked is about the second prong to our approach. It is a risk-informed process, not a risk-based process. We have deterministic risk -- deterministic factors that we evaluate in our management directive 8.3 review -- that's the terms for it -- where we go down a check list and we look for areas that would concern us.

Say this event were to happen -- well, let's say a different event were to happen. Let's say they have a problem with a diesel generator. If we have reason to believe that the second diesel, or if they have more than one other diesel, might potentially be affected that might cause us to launch and do a special inspection or something more.

We may not know the answers to that fully when this event occurs. They may not have gone through their root cause analysis or, you know, whatever, or even done a very short quick turn around, but those kind of factors would inform us, and if we have reason to doubt or question the licence -- the exten~~ded~~t of condition, amongst other things, that could cause us to do a special inspection or more.

I just wanted to share that second prong.

MR. MAYNARD: I would think there'd be a couple of important aspects. First of all, an event like this, you know, is there something going on that you need to take more look at, whether you think it's a design issue or you think it's operator performance, whatever.

As far as the safety significance of it, what I think would be important is, have you found something that is an initiator that you had not considered before, or is it something that is occurring more frequently than what was assumed in the original -- because all of these, you drop anything on the control panels and you may cause a transient, but that should not cause core damage.

But it is an initiator. And is that initiator -- is that something that is quite different, especially in frequency that might occur that might have -- change your outcome in core damage frequency?

MR. HANNA: Yes, sir. And I if I could add on to what you're saying, a lot of folks here today are from academia. You think about equations with four or five or six variables; you tweak one variable and see the effect.

To answer a previous question about why we evaluate a single performance deficiency and only that performance deficiency and look at the changing CDF or LERF, it's because that's what we're doing, is essentially a sensitivity analysis. We want to isolate that and look at it in a vacuum to see how important it is, or not important.

Does that sort of add on to what you're saying?

MR. MAYNARD: I would hope that a lot of these that we do, it doesn't have a significant impact on core damage, or we've got other issues to deal with here, but --

DR. BONACA: Although you also look at repeat events so that you don't just look at an event in isolation. You also look at the context of how many other things are happening which are of a similar nature because you want to -- or you're looking at a cross-cutting issue.

MR. LOVELESS: That's one thing I wanted to bring back up real quick, was that you were talking about licensees getting different treatment in the SDP arena and the action matrix arena based on the luck. We have this -- the evaluation of events is just one way that we inspect.

We have resident inspectors out there, we send people from the region for various inspections. If a resident inspector sees indication, or talking to people says, okay, three times in the last month some chart recorder's falling.

We may not have any major response, but he may go in as part of his routine baseline inspection and evaluate that and say, hey, this is falling apart because of a design error and you're dropping stuff on your panels that you shouldn't be, and that's a performance deficiency.

And in that case he would take that, bring it into his inspection program, find that it was more than minor, put it into the SDP process, and the licensee -- the evaluation, if they were the exact same plant, the evaluation of that and the SDP would be exactly the same as the evaluation of the event that we went and looked at on our special inspection at River Bend.

So it may make them -- the event significance makes us more likely to inspect that area, but it doesn't change the significance of the finding once we've identified it.

MR. MAYNARD: We've pretty much beat this to death here. I was wondering if there's some other question -- or other issue. I'd hate to spend our whole time on just one issue, although it is important in understanding the regulatory oversight process.

Does somebody else have any other --

MR. GODY: I was going to try another bridge and see if anybody jumped at it. I tried the EP bridge, and it didn't work.

But every time we have an issue, every time there's an event, licensees are required to take those events or those issues and develop lessons learned and train their operators or their technical staff. And that's actually a requirement in our regulations, that licensees' training programs capture lessons learned and incorporate those into training for operators or engineers.

And we've had a number of issues in Region IV where licensees weren't particularly successful in identifying -- taking issues that they learned in the plant, or even at other facilities, and weren't capturing them in their requalification programs.

And we do have a couple of examiners here; you've got a couple of EP specialists and residents, and I was wondering if anybody was interested in any dialogue on that.

DR. ABDEL-KAHLIK: I would like to ask a question about the component design bases inspections.

VOICE: Yes, sir.

DR. ABDEL-KAHLIK: As a part of this process, I'm sure you get to look at configuration management. How do you assess the adequacy of configuration management protocols?

MR. REPLOGLE: Well, it comes down -- to be honest, it comes down to instances where we think we can come up with a finding that's greater than minor in nature. If we're looking at configuration management for a certain component, or a procedure that gives operators steps they have to take to make sure that systems operate properly, if those are inadequate, we take enforcement actions.

So we walk down quite a few procedures to make sure that the procedure's steps are adequate to support the safety function.

DR. ABDEL-KAHLIK: No, I was much more concerned about design changes.

MR. REPLOGLE: Oh, design changes?

DR. ABDEL-KAHLIK: Right. And configuration management associated with design changes.

MR. REPLOGLE: That gets down to -- we find a lot of things that are minor, that don't pass the more-than-minor threshold. And we find a number of mistakes that don't have a lot of significance. Those never get documented.

We may tell a utility that, hey, we found 14 mistakes here, they're all minor, but that lends you to believe you're not properly controlling this. But as far as enforcement actions, we need to be able to develop some tangible evidence that shows that it could be more safety significant concern if it wasn't corrected.

DR. ABDEL-KAHLIK: But from the --

MR. MAYNARD: Risk management also gets looked at on a number of other aspects.

MR. REPLOGLE: That's correct. We do 50.59s and mod inspections and -- but the CDBIs look at it from the beginning to where it is now.

MR. GODY: Right. And configuration management issues really can result in weight and safety issues, and that is a concern to us. So we take every opportunity to, when we have an issue, or we have a failure, we take every opportunity to explore that issue and that failure to determine whether or not there's a configuration management issue associated with it.

For example, if a licensee were to install commercial~~ly~~ grade dedicated diodes and a voltage regulator for a generator set and those diodes were manufactured with less contact surface area in the P&P junctions and increased the probability of the diode failing due to over current, then there's a chance that you could have a decrease in the reliability of these generator sets.

So if we see a failure like that occur in the industry quite often, what we'll do is we'll inspect that and we'll particular look at whether or not those components were dedicated properly, whether or not there's a potential common thread throughout the site, maybe those diodes are used in other locations.

And we do look at the configuration management aspects of components that might demonstrate reliability issues. So that kind of gets a little bit at the -- but it's not a design -- it is a design change, I mean a commercially dedicated diode. And we've had examples where equipment's been commercially dedicated or been replaced, and we've found issues with it. And it has had common cause aspects to that, and we evaluate that.

DR. ABDEL-KAHLIK: I mean, if you go through and inspect a certain component, you're looking for a design basis, the source or information.

MR. GODY: That's right.

DR. ABDEL-KAHLIK: What if you have undocumented design basis for a certain console? What would you do?

MR. REPLOGLE: Well, that could be a design control violation. I'm flipping into regulatory space here, but a licensee need to have a documented design basis for all their equipment, and that'd be a design control violation.

Usually there is something and in most cases they have trouble finding it. And that tells us something too, if they having trouble finding the information. But the line in the sand is really the burden of proof is on us to show that it's -- it could be significant, that it could be more than minor.

DR. MALLETT: George, use the example out at Diablo Canyon with a heat exchanger --

MR. REPLOGLE: I wasn't involved with that, but

I'll talk about it if you want me to.

DR. MALLETT: I think they were giving a good example.

MR. REPLOGLE: At Diablo Canyon -- which heat exchanger was that?

(Simultaneous discussions.)

MR. REPLOGLE: Yes, CAW with -- they had salt water cooling. The heat exchanger was located at an elevation -- it was an elevation difference that was big enough between where the heat exchanger was and where the discharge of the piping went back out into the ocean to where it could pull a void at the heat exchanger.

And the licensee, what I heard is that they did know about that, but they didn't think it was a problem.

VOICE: He's going to take it.

DR. MALLETT: The point I was trying to make in answer to your question is, we did identify -- through this team saying that's a component we want to look at that could be risk significant, we did identify, and the licensee identified, there wasn't enough margin in that component like they though they had, and it had to do really with its location height-wise which affected the flows, or could affect the flows through that heat exchanger if it was needed.

So my point I was trying to make was that individual component impacted the functionality of the whole system. And so what we've found in some of our inspections, like this one, licensees were many times looking at components, but not in modifying them, but not paying attention to the whole impact on the whole system, if that makes sense, because at some point in the process, this heat exchanger was moved up the hill, or in the original design was moved up the hill in construction from where it was designed, if that makes sense. That's what I was trying to get at as an example.

MR. GODY: Yes, we actually have a pretty straightforward example of configuration management on a licensee --

DR. MALLETT: But I thought that was straightforward.

MR. GODY: No, this one's --

(General laughter.)

MR. GODY: We actually have somebody on the panel that can talk about it.

Licensees are required to operate their plant the way they're designed. Jim identified an issue at a facility where a sign had fallen.

You want to talk about that a little bit?

MR. DRAKE: This was a component design basis inspection at the SONGS power plant. Their condensate storage tank was not seismically qualified, so they built a berm around it that was seismically qualified to contain the water. And then this berm had a sump in it that would allow them to use that water to continue cooling the plant down if there was an earthquake and they lost offsite power.

But they weren't controlling the bermmed-in area as a ~~form~~ foreign material exclusion area, and as a result they had some radiation signs and other debris material that were in that bermmed area that was large enough to cover the sump grate, so it could have cut off that supply of water.

That was identified during the component design basis inspection when we were doing walk-throughs.

MR. MAYNARD: Was that their safety related source of condensate?

MR. DRAKE: It was a back-up to that, yes; it was part of their safety related water. They had two condensate storage tanks. One was in a seismically qualified tank, and that was enough to get them started.

But in order to cool all the way down, they had to have this second source of water. And so it was necessary for cooling the plant completely down, they had to be able to access that water. But because of the design of the sump and their failure to control that area of foreign material exclusion, they could have potentially lost the ability --

MR. WARNICK: This is just an open area?

VOICE: It's open to atmosphere.

MR. DRAKE: Yes, and then they put radiation signs in there to block off areas, or to rope off areas where they had a problem with, you know, radiation. So the material was down there and it could have blocked the sump.

MR. MAYNARD: Eating into your time here for some closing comments, I'd just say if there's any other burning question that any of the members have? I think it's been a good discussion. We spent a lot of time on one item, but I think we explored many aspects of that, which I think covered a number of other issues.

So with that, I'd like to turn it back over to Dr. Mallett for some comments here.

DR. MALLETT: At the risk of expanding this beyond what it should be, I'd like them to ask -- answer this question to you all. Is -- with the reactor oversight process, what would you change if you had one choice to change? I thought that might give you some insights. So nobody wants to jump out?

VOICE: You're likely to get nine different answers.

DR. MALLETT: Kelly, you want to jump up --

MR. MAYNARD: We're used to that.

MR. CLAYTON: Tough question. I think it would be nice to add more human performance aspects into the SDP. We do have trouble getting our hands around operator performance issues, and they seem to have increased. And so that would be my request as an examiner.

DR. APOSTOLAKIS: You mean more than the components and all that stuff?

MR. CLAYTON: Absolutely.

DR. APOSTOLAKIS: But why? I mean, that seems to be detailed enough. Like give me an example of something that, in your opinion, is not covered as well by the SDP as it should.

DR. MALLETT: You took the microphone.

MR. CLAYTON: It was given to --

VOICE: Kelly, if I could --

DR. APOSTOLAKIS: What is the difficulty of it? I don't want to put you on the spot, although I enjoy doing it, but what is the difficulty? I mean, you must have something in mind when you say --

MR. CLAYTON: Well, let me give you an example. In SDP space, when we do risk analysis, there is a probability during certain streams of events that an operator will take a certain action to shut a valve or open a valve, or whatever, and that gets a certain value, and that goes in these tables that the SRAs use, and so we go to a facility where their performance has been demonstrated to be poor, they repeatedly have reactivity anomalies. And a good example of that is the SONGS facility; they've had many of those in the last year.

And so the way that you get at it sometimes, the performance aspect, the human performance errors, is by modifying those values in the risk tables to downgrade their credit, if you will, on certain actions during those events.

And I would like to see more of a tool that we could use on the front end of things, where we could run it -- we don't have a SDP flow chart right now for just human performance in general. We have to get through those events, through a 41500 inspection or an SAT process inspection where we look at an operator, their history of making a mistake on something.

Sometimes we get the operator licensing folks at headquarters involved on the human performance aspects of the board, how the board was laid out, and is this switch in a bad place where it could be bumped all the time, things like that. So it gets really complicated.

But what we would like to have, or what I would like to have, is a tool, an SDP tool, that you jump with operator issues and that's what you're screening, you know, up front, and --

DR. APOSTOLAKIS: Something simpler, in other words?

MR. CLAYTON: Exactly.

DR. APOSTOLAKIS: What's your overall opinion of SPAR-H?

MR. CLAYTON: I'm not familiar with that, really. I'm not a risk analyst; I'm an examiner.

DR. APOSTOLAKIS: But you have used it though, haven't you? You're using the notebook. Right?

MR. CLAYTON: We do use the notebooks, but not as much as the inspectors do. The examiners, we use it when we're on inspections, but -- and I'm not as proficient with it as an SRA, to answer the question.

MR. GODY: Yes, where operator licensing uses the risk informed notebooks for -- and actually the PRA for -- is to identify what the risk-significant operator actions are, and we make sure that the operator license exams are risk informed by having a sampling of those risk-significant operator actions.

Now, if I was going to change something with the ROP --

DR. MALLETT: Well, we didn't ask you about --

MR. GODY: I'm not sure I want to do this. If

I were to change something with the ROP, what I would do is I would bring -- I would revisit the enforcement policy and compare it to our deterministic and quantitative risk analysis to make sure that the enforcement policy, the traditional enforcement policy, lines up with the SDP more. Sometimes you end up -- and you question whether or not you're in the right place.

DR. APOSTOLAKIS: So you would risk inform the enforcement policy?

MR. GODY: At least make sure that, you know, a severe level 3 that would be handled under the enforcement policy correlates to weight in the SDP, and not agreeing, you know, because it confuses licensees if you issue them a severe level 3 violation and if it hadn't met the criteria if you were using traditional enforcement they would have gotten a green.

It doesn't make sense. So that's an area that I would spend a little time in.

DR. MALLETT: John?

MR. HANNA: Yes. Two different areas. One, I -- Tony didn't mention during my bio that I come from a biopsychology -- that was like my specialty -- background, aside from mechanical engineering, at Georgia Tech, and one thing that's always bothered me is the fact that there's not uniformity in the definitions of human performance.

You have the NUREG-1020 or -- I'm trying to remember that NUREG -- I'm looking over at operator licensing folks.

MR. CANIANO: 1021.

MR. HANNA: 1021. Thank you.

And then there was all these different criteria definitions, so there's no uniformity between the industry and us on these various measures.

The other thing is sometimes the risk analysts get into -- like they give us a number on a core damage frequency, and I'm always wondering what the band width is on this. I think of a distribution curve, or possibly -- it'd be nicer to know what certainty we're talking about.

Now, they end up usually quite often doing sensitivity analyses to justify the phase 3 that they come up with. But it would be nice for inspectors, and possibly make it more scrutable to the public, get a number you can see how wide that number is which speaks to our uncertainty about it. It would be graphical; it would be scrutable.

DR. APOSTOLAKIS: Have you talked the headquarters guys about this?

MR. HANNA: No.

DR. APOSTOLAKIS: Because the message we're getting from them is that distributions would confuse people.

MR. HANNA: Could be. That's -- no, I didn't talk --

DR. APOSTOLAKIS: Well, that's --

MR. HANNA: -- to headquarters. This --

DR. APOSTOLAKIS: -- I'm glad you said --

MR. HANNA: -- is just my little two cents in a vacuum.

MR. WARNICK: All right. I guess this is a difficult situation for me, since I just spent time earlier telling you how successful the ROP has been in a case study from Palo Verde.

But something that I needed a change for were resources for inspection. We've been allowed N inspectors at Palo Verde; that equates to three inspectors. But I've needed additional help for some time, and actually we finally got approval. Bruce helped us, up through Jim Dyer to get N+1. We actually have an additional inspector coming out in September, which will help greatly with the resources.

And additionally I'd like to say that -- I talked earlier about how the revised oversight process was successful in us directing our regulatory resources to oversee Palo Verde in the way that we felt was needed.

However, as Bruce kind of mentioned earlier in my discussion, I felt the need for more regulatory oversight earlier than the process allowed us to provide.

I saw a lot of indicators early on, was uneasy about the performance at Palo Verde. Yes, we still had to go through the process to eventually get the licensee to call them forward based on their performance, where, again, I felt that this level of oversight was needed since they were struggling with correcting their problems and implementing the plans that they developed.

DR. SHACK: If you had the new safety-culture thing in place when all this started, would that have made a difference?

MR. WARNICK: Well, the new safety-culture piece would have been done, I guess, to a certain extent with the 95002 inspection. A licensee would have known that that was a piece of this, so they obviously would have taken actions to address that.

They did -- getting to your question, they did do some safety-culture type investigations back at that time period, however. In fact, they had the same group that came in recently come into Palo Verde in the 2004-2005 time frame, Synergy, to do some safety-culture assessments.

We did -- the results out of that, as far as the licensee was concerned, was that it was relatively positive. However, if you looked at it real closely, it caused us to have additional concerns.

To a certain extent it would have allowed us to have additional concerns, but a licensee was looking at it and still they failed to correct the problems that they had out there to the extent where they are currently.

MR. LOVELESS: David Loveless again. My biggest concern with the ROP as it exists now is that the SDP continues to expand in its use of resources with very little increase in the benefits that we've been getting from it.

I can show examples where we've spent 1,000 plus man hours to determine whether something is either green or white. We have examples of where licensees have spent $3 million in a test because they didn't want to indicate white on their -- in the matrix.

We are being pushed by the licensee quite often, but also from our program offices, to get a more and more precise number in our SDP to justify going over the green threshold, and in most of those cases it's because of push back from the licensees.

But the root cause, in my opinion, is that we haven't gone out as an agency and set bounds and said, you know, the primary reason for making a green/white decision is so that we can allocate our resources, and we're allocating 40 inspection hours on a 95001.

How can we justify spending 2,000 man hours and a licensee spending $3 million to decide whether we expend 40 hours of resources in the field? So that's where we need to improve.

DR. MALLETT: Anyone else? Jim?

MR. SHUKLA: Yes. Just a minute. I have a question --

DR. MALLETT: We've got a quick question here.

MR. SHUKLA: Yes, my name is Girija Shukla. I'm the senior program manager for the ACRS. I was very impressed this morning to hear about the knowledge management and all its sharing, and I was wondering whether this kind of information is relevant to the industry, and if there is any way to monitor their use.

Like Greg said, that all the indications of poor performance we couldn't deal with them because we had no program, we didn't put out a program at that time. But if we had some way to share this information with the licensee, they can take some action, put those in the corrective action programs and so forth so other people don't become complacent to something like this.

So is there any way we can share our knowledge, a transfer mechanism like, you know, newsletters or whatever we share with each other with the industry and somehow we could monitor whether the licensees are using those tools would be much beneficial.

DR. MALLETT: I'll start out on that. We have been -- that's a very good point, and we have been using various mechanisms to share this information.

One is, as the senior leaders, Dwight Chamberlain and myself, and the other senior managers in the region, meet with the site plant managers at least once, sometimes twice a year, in Region IV. We meet with the site vice presidents at least twice a year.

We also meet with the Regulatory Affairs managers, and we bring up these issues with them. And they -- just a forum similar to this, for about a half a day, and they bring up issues with us as well. So that's a great forum where things are shared.

I think also the residents do an excellent job of sharing these things in their meetings they have with the site managers and other members of the licensee's team at the site. Licensees share things in their operational experience program through INPO.

They have asked us to come up with an operational experience program where we share inspection results, because if you're recognized on the reactor oversight process -- we changed to not put much detail in the inspection reports, so they don't get a lot of these observations any more to share early on.

And that's something they've asked us for at least the past couple of years now, is there a way we can share operational experience from inspection reports. And we've kicked it around but haven't done much in that area. But I can tell you, I knew their regulatory affairs manager shared.

So I don't know if that answers your question, Girija, but I think it's very important --

MR. LOVELESS: Right. The one -

DR. MALLETT: -- those forums that we do, so.

MR. LOVELESS: -- one thing I would add to that is that we do have counterpart meetings. For example, in operating licensing, west train, we actually about every six months get together and talk about issues, talk about lessons learned from exams and inspections findings. We have EP counterpart meetings; we just had the NEI counterpart meeting in New Orleans. We have RUG meetings where we talk about plant issues. So we have very -- numerous meetings to discuss about issues and lessons learned.

DR. SHACK: Just a quick -- back to Mr. Loveless's point. You know, what would you do? I mean, you're trying to draw a sharp boundary with uncertain values, and, you know, to a certain extent -- I mean, you're just going to have live with that. Is that -- you're just saying that you realize that's true and stop the analysis rather than trying to flesh it out?

MR. LOVELESS: That's pretty much what I'm saying. We have invested a lot of time and effort into some tools, and we could argue the strength and weaknesses of those tools. But at some point we could go out as an agency and say, Our phase 2 notebooks have been developed, and for all components modeled within those notebooks, if you have a component out of service, that's failed, and we follow the phase 2 notebook and it comes up white, that's the answer.

If you don't like the tool right now, let's talk about it up front why the tool should be improved. But that is our tool, that's how we're going to do SDP. And then on our yellow and red findings, the ones that are much more significant, that have much more of an impact to licensees, then we have the broader licensee inputs, and it's worth our time and effort to spend more time, to try to analyze those additional risk factors.

DR. MALLETT: Yes, I would add to that I think it's very important between us and the licensee that we come to some alignment on the assumptions that are made in the analysis, because those can make a big difference one way or the other.

But many times where the answer comes out very clear, we don't have a problem. It's that interface, the green/white interface, is where we have the issues now. And so we embarked upon -- Dwight Chamberlain did a study, as I indicated earlier, to map out the process.

And what we embarked upon was there has to be a decision made, right or wrong, these are the assumptions we're going to use, these are the differences between what the licensee came up with and we came up with, here's our answer.

And many times it comes out -- and you've seen me draw this before -- it comes out a spectral analysis of -- scatter-plot, if you will, all around that interface. And many times you have to say, well, is it more likely, what's the best answer than not that it's white or is it green.

And that is a problem, but I think David's right. At some point you have to say enough is enough, it's not longer going to be a research project, and we're done with it.

MR. MAYNARD: Yes, and I don't disagree with that. I think you -- I can understand why it's important in some cases. It's not just a matter of how many resources are put on an inspection because when something does cross the line, then that also sets up -- it's another thing closer to a degraded cornerstone or something like that.

So it has other implications, and I think you'll always get some push back from the industry. And I don't think that's bad. I think that it's good for the regulator and the industry to discuss these things and to push those up. I do agree at some point somebody's got to make a decision and say, this is what we're going to do.

But it does go beyond just whether or not we put some additional resources on an inspection or not. It has other implications; that's why it's important to have some good basis for it.

DR. MALLETT: I agree totally. It has implications for the regulator and the licensee, much, much far beyond resources.

DR. SHACK: Let me just come back to the tools that you use. I mean, I thought the SRA would be off looking at this thing with SPAR-H, and the inspector would be using the notebooks. Are most of the analyses really done with the notebooks and it stops there?

MR. LOVELESS: No, none of them are.

DR. SHACK: None of them are.

MR. LOVELESS: None of them are. And -- but -- you know, as an example, our -- the -- what we'll accept and how much information we analyze and to what level we analyze it is changing, as opposed to getting to a point where we say, okay, these are things that are acceptable for the analysis, these are things that aren't.

We recently had an issue where we spent a large amount of time trying to decide whether a facility that had a diesel generator fail, and they came in and said, well, we could have recovered this diesel generator.

How could they have? And I'm going to give as fair an assessment as I can, they would have had to send out an INC team, they would have had to determine that a voltage regulator had failed, then they would have had to determine that a voltage regulator failed in a very specific way.

Then engineers would have had to determine that, hey, with the voltage regulator failing this way, we could manually bring this machine up using a method we've never done, we don't have procedures for, and then having the operators, with this unique evolution, bringing this machine up.

Under my way of doing business, we would never have allowed that entire evaluation. We would have said, this is beyond what we're going to consider as valid risk, when you're comparing it with a PRA that's not modeled anywhere near that level, because every time you model to -- something to a different level, you artificially change its significance.

And yet we were directed and spent many, many hours trying to decide what's the probability that the licensee could have done this action. And --

DR. MALLETT: Let me add to that, David. This is a case that's currently being discussed, so I want to be careful. But I can tell you that I think it was good in this case because it has some implications for the licensee to go a little bit further. But what we have been trying to do lately is identify where the differences are and make a decision.

In the past, you'll find back a couple of years ago, we were not doing that, and these might go on for six months, some of them. Now we're making that decision before we get to the 90-day mark. And I think that's healthy. And it does -- there are different views on them. I think that's healthy to have a consensus process.

VOICE: Since you're still --

DR. MALLETT: Well, let me try and shorten up a summary here, then. I will say this, I think that -- I would add one thing. The issue of the 95003 in safety culture, one of the things we're tasked to do in the Palo Verde case, because it's our first case of reviewing with this new procedure, is to look at our own procedures to see do we have the right guidance out there, do we have the right things we're looking at?

So we will feedback to determine is this the right look at safety culture, is this the right way to look at it.

I would summarize today by saying we did try to provide you a spectrum of individuals to talk to and present their views on our oversight of reactors programs in the regional office. I think we've done that. We tried to use case studies. I know it's difficult sometimes to talk about those, but we try to help you in that area.

I would encourage you to give us feedback if that's the right thing to do, because the next time you meet with another region they'll pattern off of what we did.

And then I would add this at the end, is the program identifying the right issues? I think that's dependent upon three things, you can maybe add to this list, but one is that we revisit the program every year, and we build into this reactor oversight process doing that.

My worry, besides not turning over every rock -- that's one of my worries I said earlier today -- is that we'll stop that revisiting of the program and think we've reach Mecca. I think that's one key item to this program, to make sure we keep revisiting it.

You help that by coming and asking us these things. I can guarantee you we'll discuss your visit after you leave for what did we learn from that ourselves.

DR. SHACK: But there is a formal feedback mechanism to this.

DR. MALLETT: There definitely is a formal feedback mechanism that has --

DR. SHACK: You assume that it's going to disappear?

DR. MALLETT: No.

DR. SHACK: No.

DR. MALLETT: That has pros and cons to it. But I do know in the previous system, over a period of time, that change in the process and looking at it faded away. And so I'm hoping that we don't fade it away in this process.

I also think it -- another key to success are the people you see sitting around this table and in this room, and keeping their expertise, because I think that's a key part of any process, to knowing what to look for.

And then last I'll make my plug again for turning over every rock. I think we have to continue to be diligent in the process.

And I want to thank all the people today. I think you all did an outstanding job, and I think you gave them -- I hope we gave you the insights you were looking for.

MR. MAYNARD: Well, good. Well, thank you very much. And before I ask the members for some comments there, I would like to open just real briefly to if there's anyone from the public that has a comment they'd like to make, or anything, I'd give an opportunity here.

(No response.)

MR. MAYNARD: Give the public one minute and the NRC all day.

All right. With that I'd like to just kind of go down the line --

DR. WALLIS: Well --

MR. MAYNARD: -- and see if you have any comments.

DR. WALLIS: -- I would say I liked the case study approach when the question was asked, but I've heard it from the other regions. It's good to hear stories of what happened and how the region responded, how the licensee responded, how things were resolved or not resolved, and what we learned from it.

I like the case study approach. I found those were useful this time, I found them useful before when we visited regions. So that would be my comment to take away.

MR. MAYNARD: George?

DR. APOSTOLAKIS: Well, I liked the whole meeting. I was very impressed by your presentations. I think we have top people here and they understand the methods and what the agency is doing. So I was very happy with this meeting. And I do like the case studies very much; I enjoy those.

MR. MAYNARD: Bill?

DR. SHACK: Again, I thought it was a very good meeting. I guess, you know, I like the case studies. I'm intrigued by SDP, which was always, you know, one of the final places we end up hearing -- next time I'd like a more detailed -- you know, really go through a case study with an SDP, and let me see how it goes from the inspector to the SRA, and maybe back and forth. I'm thinking that that I would find that valuable.

DR. MALLETT: I think we arrange that if we have about two, three days to --

DR. SHACK: Well, I realize that may take up a chunk of time, but I think it could be worth it.

MR. CANIANO: Dr. Mallett has mentioned that we did have a study. It took me two months to go through that.

DR. SHACK: But see you've got it all worked out now.

DR. BONACA: I can only repeat what my colleague said. That was a great meeting, I think it was well informed, a big effort, real hard to put together. It was a very well prepared presentation. I like the case studies.

I wish we had, by now, more experience of the improvements of the safety culture and see, you know, but still you have to have experience on that, and time will tell.

In general I thank you all for the -- for an outstanding presentation.

DR. CORRADINI: I guess I'll lend my voice to thanking you for your time and all that we've learned. I'm new to the committee, so a lot of this I was learning for the first time, relative to the inspections and the procedures.

The one thing I guess that I would say -- I'm not going to say anything about the case study, or else that would be too unanimous -- no, I thought it was good -- is that from a knowledge transfer, a knowledge management standpoint, I was interested in that primarily because I'm more -- I'm, to a large extent, interested in how the history of how the agency is changing with a whole new set of people coming in and potentially a whole new set of plants starting up.

And so that's why I was quite interested in a lot of what you're doing now. And I appreciate the time you've given this. Thank you.

DR. ABDEL-KAHLIK: Yes, I'd like to reiterate what my colleagues have already said. This has been a very informative and very well organized and thought out meeting. I would add my thanks to those expressed by my colleagues for the time and effort you've devoted to this presentation today.

MR. MAYNARD: Well, I do appreciate everybody's involvement in the meeting. Relative to case studies, I do think that's a good approach. I will say I think we need to be a little careful sometimes, and we were talking fairly freely. This is a public meeting, and some of the comments that we've made that aren't really part of the official record I think could be interpreted by some maybe inappropriately.

I think we have to be a little careful in how we -- or what we say on some of our opinions of what went on in some of these, and try to stick to what happened and how did that really affect the regulatory oversight process and stuff, because, you know, people will read the minutes from these meetings and read things, and certain things probably be taken out of context could create both -- problems for both the regulator and for licensees and stuff, maybe unnecessarily so.

I do think it's a good process and I think it's a good way to get into how the process works. I would offer some caution just how -- you know, what we say about some personal opinions on some things in a public meeting, they're -- may or may not be valid, especially where we don't provide an opportunity for the licensee to come in and maybe present their perspective on some of the things.

I don't think there would be much disagreement on the facts of what happened and stuff. There would be some, but, you know, I think that some of the other stuff that gets filled in there that might -- I was very impressed with just the overall interaction among the Region IV staff. I didn't see any hesitancy in anybody speaking up, of correcting somebody, if they had additional information or whatever.

I think that shows good teamwork and respect for each other that I think is critical to the success of an organization, to feel that for you to be able to talk and provide your input. So I was impressed with that, and commend you on that. And I think that reflects very positively upon your overall staff here. So I was impressed with that.

I'd like to say I really appreciate the hospitality, and I think you met all of our needs and everything here. I think that everybody got what they wanted. Had to push some people along at times here, but, you know, a number of these things we could probably talk for days on.

With that, if there's no last-minute comments, which I won't give more than a half a second for, I'd like to go ahead and adjourn the meeting and call it to a close. So thank you very much.

(Whereupon, at 4:10 p.m., the meeting was concluded.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards

Docket Number: n/a

Location: Arlington, Texas

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Penny Bynum

Penny Bynum
Official Reporter
Neal R. Gross & Co., Inc.

ACRS Visit to Region IV Attendees

ACRS Members

Dr. William Shack, ACRS Chairman
Dr. Mario Bonaca, ACRS Vice Chairman
Otto Maynard, ACRS Operations Sub-Committee Chairman
Dr. Graham Wallis, ACRS Member
Dr. Michael Corradini, ACRS Member
Dr. George Apostolakis, ACRS Member
Dr. Said Abdel-Kahlik, ACRS Member-at-Large

ACRS Staff

David Bessette, ACRS Staff
Maitri Banerjee, ACRS Staff
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Girija Shukla, ACRS Staff

Region IV Staff

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Dwight Chamberlain, Direction, Division of Reactor Safety
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Linda Howell, Chief, Response Coordination Branch
Linda J. Smith, Chief, Engineering Branch 2
Dr. D. Balir Spitzberg, Chief, FC & D Branch
David P. Loveless, Senior Reactor Analyst
John D. Hanna, Senior Project Engineer
George Replogle, Senior Project Engineer
Kelly Clayton, Senior Operations Engineer
Wayne Walker, Senior Project Engineer
Greg Warnick, Senior Resident Inspector
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James F. Drake, Operations Engineer
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Fred Madden, Director, Oversight and Regulatory Affairs, Luminant Power, Comanche Peak
Michael McBrearty, Nuclear Regulatory Affairs Division, San Onofre Nuclear Generating Station

Exhibit 4 - ACTION MATRIX

		Licensee Response column	Regulatory Response column	Degraded Cornerstone column	Multiple/ Repetitive Degraded Cornerstone column	Unacceptable Performance column	IMC 0350 Process
RESULTS		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
RESPONSE	Regulatory Performance Meeting	None	Branch Chief (BC) or Division Director (DD) Meet with Licensee	DD or Regional Administrator (RA) Meet with Licensee	RA (or EDO) Meet with Senior Licensee Management	Commission meeting with Senior Licensee Management	RA (or EDO) Meet with Senior Licensee Management
	Licensee Action	Licensee Corrective Action	Licensee root cause evaluation and corrective action with NRC Oversight	Licensee cumulative root cause evaluation with NRC Oversight	Licensee Performance Improvement Plan with NRC Oversight		Licensee Performance Improvement Plan / Restart Plan with NRC Oversight
	NRC Inspection	Risk-Informed Baseline Inspection Program	Baseline and supplemental inspection procedure 95001	Baseline and supplemental inspection procedure 95002	Baseline and supplemental inspection procedure 95003		Baseline and supplemental as practicable, plus special inspections per restart checklist.
	Regulatory Actions	None	Supplemental inspection only	Supplemental inspection only	-10 CFR 2.204 DFI -10 CFR 50.54(f) Letter - CAL/Order	Order to Modify, Suspend, or Revoke Licensed Activities	CAL/order requiring NRC approval for restart.
COMMUNICATION	Assessment Letters	BC or DD review/sign assessment report (w/ inspection plan)	DD review/sign assessment report (w/ inspection plan)	RA review/sign assessment report (w/ inspection plan)	RA review/sign assessment report (w/ inspection plan)		N/A. RA (or 0350 Panel Chairman) review/ sign 0350-related correspondence
	Annual Public Meeting	SRI or BC Meet with Licensee	BC or DD Meet with Licensee	RA (or designee) Discuss Performance with Licensee	RA or EDO Discuss Performance with Senior Licensee Management		N/A. 0350 Panel Chairman conduct public status meetings periodically
	Commission Involvement	None	None	None	Plant discussed at AARM	Commission Meeting with Senior Licensee Management	Commission meetings as requested, restart approval in some cases.
		INCREASING SAFETY SIGNIFICANCE ---------->					

Note 1: Other than the CAL, the regulatory actions for plants in the Multiple/Repetitive Degraded Cornerstone column and IMC 0350 column are not mandatory agency actions. However, the regional office should consider each of these regulatory actions when significant new information regarding licensee performance becomes available.
Note 2: The IMC 0350 Process column is included for illustrative purposes only and is not necessarily representative of the worst level of licensee performance. Plants under the IMC 0350 oversight process are considered outside the auspices of the ROP Action Matrix. See IMC 0350, "Oversight of Reactor Facilities in a Shutdown Condition due to Significant Performance and/or Operational Concerns," for more detail.

NRC Inspector Field Observation Best Practices

November 2005

PHONE NUMBERS

NAME ______________

PHONE NUMBER ______________

HEADQUARTERS OPERATIONS OFFICE ______________

CONTROL ROOM ______________

RP CONTROL POINT ______________

SECURITY ______________

RESIDENT OFFICE ______________

REGIONAL DUTY OFFICE ______________

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NOTES

TABLE OF CONTENTS

PURPOSE

This booklet has been developed primarily for new inspectors. In user-friendly language, it provides guidance and contains useful inspection tips. The material presented was developed by inspectors and combines best practices of all four regions.

NOTE: The guidance is not intended to be all inclusive, but rather to supplement existing inspection procedures to heighten inspector awareness and improve the effectiveness of plant walkdowns. Official agency guidance or policy is promulgated in NRC's inspection manual.

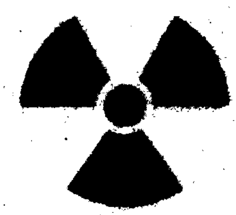
GUIDANCE ON PLANT INSPECTIONS

The following plant observation opportunities are a compilation of issues identified in generic correspondence, such as Generic Letters and Information Notices, as well as other correspondence, such as Value Added Findings (VAFs).

Personnel Performance

In addition to obvious plant equipment issues, inspectors should also be aware of the activities of licensee personnel working around them. Particular attention should be given to the following specific areas:

Radiation Protection Standards and Practices: Verify that plant workers are adhering to proper radiation protection standards and practices at the facility. For example, verify that plant workers are wearing radiation dosimetry in conformance with facility-specific requirements and maximizing the use of low-dose waiting areas. During containment and other contaminated area entries, observe plant workers and verify that they are properly donning anti-contamination clothing before entering the area and properly doffing their protective clothing upon exiting the area. Verify that workers passing tools and other equipment across contaminated area boundaries are following good radiation protection practices and do not violate or compromise radiation boundaries.



Fitness-For-Duty: Note whether plant workers are exhibiting indications that they may not be fit for duty (slurred speech, alcohol on the breath, lethargy, closed eyes, etc...). Immediately reported any observations of fitness-for-duty issues to licensee management.

Horseplay: Look out for "horseplay." Report any observations immediately.

In-Hand Procedures: Verify that operators using in-hand procedures in the field follow the instructions in those procedures.

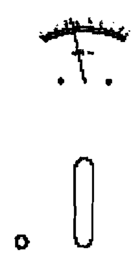
Unauthorized Operator Aids: Operator aids are instructions, cautions, labels, or other markings on or near plant equipment to help a plant worker perform an activity. Some operator aids have been formally reviewed and approved for use, but most have not and are therefore unauthorized. Unauthorized operator aids are relatively easy to identify since most are handwritten on the equipment. Look out for potentially unauthorized aids and report them to licensee management.

Clearance (Tagging) Activities: Improper performance of clearance (tagging) activities can lead to personnel safety hazards such as electrical shock and increase plant risk by causing internal flooding, increasing ignition sources, and compromising defense-in-depth. During routine plant entries, watch for equipment clearance tags on equipment associated with risk-significant maintenance or modifications and verify that the clearance tags have been properly hung by comparing the information on the tags with the configuration of the equipment. (NOTE: DO NOT manipulate equipment! Verify equipment configuration by visual observation or seek the assistance of a plant operator.)

Stop - Look - Listen - Learn Stop and stand in an area for 5 to 15 minutes. It's amazing what will stand out or who will walk by with an interesting story.

Foreign Material Exclusion (FME) Controls: The introduction of undesired (foreign) material in plant systems and components can have a significant negative impact on plant components. Licensees must therefore have adequate foreign material exclusion (FME) controls in place to ensure that foreign material is not introduced into systems during maintenance or other activities in which system boundaries are breached. During routine tours near maintenance activities, verify that licensee personnel are taking precautions not to introduce foreign material. Verify that piping and system components that would otherwise be open are covered or plugged with a prefabricated FME device. In some more strict cases, such as during work on the main turbine during an outage, licensee controls may include roping off the work area and logging tools and other equipment in and out of the area to avoid leaving anything behind. If this type of activity is taking place, verify that it is being carried out effectively and consistently and that other uncontrolled entry points do not exist. Well-defined areas of the refueling floor or fuel handling building should have strict FME controls around the spent fuel pool. Review the FME control log to ensure that appropriate controls are being maintained.

Component Related Issues

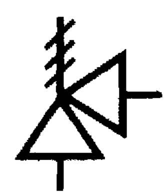


Gauges: Verify that gauges for operating equipment parameters are indicating within the normal operating range. For example, a gauge that is "pegged" high would certainly warrant additional discussion with the licensee to verify that the associated equipment is functioning properly and that the gauge itself is not damaged. Similarly, a gauge with a bent needle could indicate an extreme over-range condition, potentially impacting the calibration of the gauge.

Thread Engagement: Issues involving the thread engagement of fasteners or missing fasteners have been frequently identified. This type of issue can impact the seismic qualification of the associated equipment and therefore overall operability. For nut/bolt arrangements, verify that all portions of a fastening nut are fully engaged with its associated fastening bolt. Verify that screws and similar fasteners are in place and appear to be tight.

Check Valves: Check valves commonly have an arrow or some other marking stamped on them to indicate the proper direction of fluid flow. Based on the arrangement of piping and other equipment such as pumps, verify that the orientation of a check valve appears correct.

Relief Valves: Similar to check valves, relief valves can be installed backwards. Look at the marking to verify that these valves are properly installed. Verify that relief valves are un-gagged when in service. Relief valves often have vendor-supplied nameplate data indicating design rating (i.e. lift pressure). This should align with the design basis of the system and, in general, be identical to other similar relief valves.



Welds: Be aware of the potential impact of fatigue on piping welds that are subjected to constant or frequent vibration. Visually check that piping welds are structurally sound with no obvious cracks. Some obvious signs of a failed weld would be steam or water issuing from the crack.

Pumps: Pumps cavitate when fluid pressure near the eye of a pump is reduced to the point that cavities form in the fluid. When this happens, the cavities or bubbles collapse when they pass through the regions of higher pressure at the pump discharge resulting in noise and vibration and possibly damaging many pump components, including the pump impeller. Over time the efficiency and capacity of the pump decreases, sometimes to the point that the pump is no longer able to perform adequately. Be aware of this condition and look and listen for the symptoms of pump cavitation.

Oil Reservoirs: Verify that oil reservoirs and other lubricating oil containers are sufficiently full for the associated equipment to operate as designed. If the reservoirs have high/low marks, verify that the oil level is where it should be. A piece of equipment may have a placard to instruct personnel on the proper oil level. Question an empty or nearly empty oil reservoir on an otherwise operable piece of equipment. Observe the color of the oil in the oil reservoir and verify that the color is consistent with the color of the oil in the oil reservoir in a redundant piece of equipment. Excessive oil leakage on a component exhibited by saturated rags or oil puddles may be masked by equipment operators who frequently provide makeup oil to the component. This excessive leakage may prevent the component from operating without makeup.

Spring Cans: Verify that spring cans associated with operable equipment do not have pins or locking devices installed to prevent their operation. This issue is of particular concern following a refueling outage or system overhaul activity where spring cans may have been pinned prior to the draining of system piping and components. Connections should have all fasteners in place with proper thread engagement.

Pipe Supports/Snubbers: There are basically two types of snubbers: hydraulic and mechanical. Hydraulic snubbers indicate whether they are inoperable and whether the hydraulic fluid reservoir is empty. For mechanical snubbers, the operability can only be determined by a physical test. The material condition of a snubber, like any other pipe support, can be inferred by looking at the overall installation. Any misalignment of the pipe clamp and the snubber may indicate a problem. Any deformation or other sign of overloading may also indicate a problem, such as a waterhammer.

Circuit Breakers: With breakers in any position other than the seismically qualified racked-in position, the Class 1E switchgear might not function as required for a design basis seismic event. The term "racked out" is defined to include any breaker position other than the fully connected operating position. There are several intermediate positions, depending on the manufacturer and model of the switchgear, such as the "test" position in which the primary contacts are disengaged but the secondary contacts are in place so the breaker can be tested; the "disconnect" position in which both the primary and secondary contacts are disengaged, but the breaker is still in the switchgear cabinet, and in some cases, restrained; and the "removed" position, which is similar to the "disconnect" position, but the breaker is not restrained. These intermediate positions may not be seismically qualified. Question the qualification of Class 1E switchgear whenever the breakers in the switchgear room are observed to be in any position other than the "racked in" position. Breakers free of the cabinet and any other loose equipment on wheels should have the wheels chocked to prevent movement.

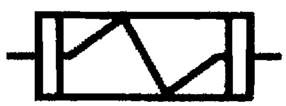
Follow the string, extension cord, temporary label, or anything out of the ordinary. There's usually a story.

Tape and Markings Containing Chlorides: Although seemingly harmless, tape or markings on stainless steel piping can cause transgranular stress corrosion cracking as a result of the leeching of chlorides and can result in piping failure. Watch out for tape or markings on stainless steel piping and report observations to licensee personnel.

Lighting: Verify that areas are illuminated properly through the use of permanently installed, operable lighting. Verify that lighting installed on chains or other devices allow lighting to swing freely and cannot adversely impact safety-related equipment during a seismic event. At some sites, a restraining chain or rod is used to prevent overhead light fixtures from swinging in one direction or another in the vicinity of safety-related equipment. Verify that such devices are properly installed.

Scaffolding: Verify that scaffolding is erected in accordance with the licensee's scaffolding erection procedures. Pay particular attention to scaffolding installed in safety-related areas. Verify scaffolding is not directly attached to instrument racks or piping supports, does not interfere with the operation of equipment such as ventilation dampers, and does not block access to fire protection equipment such as hose reels, fire extinguishers, and fire doors.

Heat Exchangers: A significant amount of industry operating experience exists regarding the clogging of heat exchangers and coolers. Observe the flow of coolant through this equipment by local indication and identify any low-flow condition through a comparison with flow indication from a redundant heat exchanger. Compare the orientation of the end bell of one heat exchanger to the orientation of a similar redundant train heat exchanger end bell to confirm proper configuration (an improper end bell orientation can significantly reduce or isolate flow to an otherwise functional heat exchanger). If you have an opportunity to observe the reassembly of a heat exchanger, verify that gaskets are properly installed such that the cooling water flowpath is not blocked or restricted.



Electrical Panels: Confirm that electrical panels are in good material condition. Verify that electrical panels have all bolts and/or thumbscrews securely in place to ensure seismic qualification is maintained, and that an excessive amount of dust or debris on the panels is not present. Verify that electrical panels and cabinets do not have holes or other openings that could allow moisture to penetrate the outside of the cabinet. Other signs of electrical cabinet degradation are excessive heat outside the cabinet and abnormal sounds or smells.

Conduit Seals: Verify that conduit seals are properly installed and are in good material condition. Verify that conduit seals are properly attached to conduits that contain instrumentation (signal) cables associated with the reactor protection system. These seals, if improperly installed, can allow interference signals from radios or other devices to initiate a reactor trip signal.

Seal Leakage: During operation of raw water systems such as service water that can have varying amounts of seal leakage, verify that any seal leakage is not spraying on the adjacent bearing housing (significant water intrusion into the bearing housing can occur in certain conditions). Spray shields can also inadvertently direct the leakage to the bearing housing.

Motors: Verify the material condition of motors when in operation. A motor that is operating with degraded windings or some other material condition issue can frequently be detected by resting the back of a hand (for personal safety) on the casing of the motor and comparing the temperature to the temperature of a similar operating motor. Motors can also overheat if the motor vents are blocked or clogged by an accumulation of grease and dust. Verify that motor vents are free of such debris.

Watch for and take advantage of opportunities to tour normally inaccessible areas.

Freeze Seals: Freeze seals are used to isolate components during maintenance in locations that cannot otherwise be isolated. The seal is created and maintained by applying a cooling agent such as liquid nitrogen to the exterior of the piping. The cooling agent freezes the water within the piping section, sealing the pipe. Freeze seal failures can be significant because of the potential for consequential failures such as the loss of decay heat removal or unexpected loss of primary coolant. Verify that freeze seals are being properly monitored and maintained.

Submergence of Electrical Circuits: In some cases electrical cables that have been submerged in water for an extended period have degraded to the point of failure. Typically, these cables are underground and can only be accessed through inspection manholes. Although it is unlikely that these manholes will be open for inspection, if the opportunity arises, verify that underground cables are maintained in a dry environment. If cables are found submerged, verify that the cables are designed for that environment and that other conditions that could adversely impact the cable, such as corroded cable supports and cable jacket tears, do not exist.

Boric Acid Corrosion: Boric acid is used in pressurized water reactors as a reactivity control agent. Its concentration in the reactor coolant is normally less than about 1.0 weight percent. At this concentration boric acid will not cause significant corrosion even if it comes in direct contact with carbon steel components. In many cases, however, coolant that leaks out of the reactor coolant system loses a substantial volume of its water through evaporation, resulting in the formation of a highly concentrated boric acid solution or boric acid crystal deposits. A concentrated solution of boric acid may be very corrosive and if not addressed can have a significant adverse impact on plant components, particularly on carbon steel. The most effective way to prevent boric acid corrosion is to minimize reactor coolant system leakage. This can be achieved by frequent monitoring of the locations where potential leakage could occur and repairing the leaking components as soon as possible. Verify that there are no boric acid leaks (by looking for boric acid residue) and inform licensee personnel of previously unidentified leaks or if it appears that leaks may not have been fixed.

Waterhammer: Waterhammer is an impulse load created by the sudden stopping and/or starting of a liquid flow which may occur when a valve is opened or closed. The resulting pressure load can have a catastrophic impact on pumps, pressure transducers, turbines, and valves. Waterhammer events typically occur in milliseconds but may last several seconds in large systems. Obvious signs of waterhammer damage include piping, supports, and other structural components which are physically distorted. Other signs of waterhammer are a "pinging" noise and/or visible piping deflections when the system is in operation. A more subtle sign of waterhammer damage is slightly displaced supports. Look for paint scraping off piping as the support is forced along the piping by the waterhammer. Look for wall support plates that are separated from the wall by a gap larger than the thickness of an index card. Inform licensee personnel about potential waterhammer damage.

Get out in the field, especially during testing and outages. When you know what "normal" looks like, "abnormal" will jump out at you.

Heavy Loads: The movement of heavy loads, such as the reactor vessel head, can have a catastrophic impact if these loads were to fall unexpectedly. Keep informed about schedules of heavy load lifts. Verify to the extent practicable that they are being conducted safely. Verify that the crane or lifting device is rated above the weight of the load being lifted. Verify the rigging is in good physical condition and has been properly inspected. Look at the general condition of the crane or lifting device. Immediately inform licensee personnel about any cracks indicative of an overloaded condition. Verify that the licensee is following the previously evaluated safe load path.

Painting: Painting can have a positive impact on material preservation and overall equipment appearance, but if not properly done painting can make equipment inoperable and unavailable. Verify that licensee painting activities have not adversely impacted the painted equipment.

Verify that vent holes on pump casings and oil reservoirs have not been painted over, affecting equipment performance. Verify that painting in the vicinity of moving equipment such as emergency diesel generator fuel racks does not inadvertently "lock up" the fuel racks, preventing the diesel from attaining rated speed. Another aspect of painting activities to consider is the detrimental impact of paint fumes on the charcoal filters of an emergency filtration system such as the Standby Gas Treatment System in a boiling water reactor. If these systems are in operation during or soon after a painting activity, the charcoal filters may be rendered inoperable in a very short period of time, effectively rendering the entire safety-related system inoperable. Confirm that painting activities are not being conducted in conjunction with emergency filtration system operation (e.g., during surveillance testing).

Housekeeping: Look at the overall cleanliness of the plant, commonly referred to as "housekeeping." Housekeeping indicates the general attitude of licensee personnel. For example, a licensee organization that demands that the plant be maintained in a good housekeeping condition is also likely to have strong standards regarding other, more significant, aspects of the operation of the facility. Housekeeping issues that could result in a personnel safety hazard, such as standing water, should immediately be brought to the attention of licensee personnel.

Control Room Observations

Inspectors conducting inspections in the licensee's main control room have an opportunity to observe plant parameters and conditions that, although not necessarily directly related to the primary purpose for their inspection, can provide valuable information concerning licensee performance. In particular, the inspector should look for system components that are in an unexpected configuration or parameters that are at unexpected values based on the operational mode of the plant. Note any adverse plant parameter trends and whether the licensee is aware of the trends. Note whether the plant is in any technical specification (TS) limiting conditions for operation (LCOs), whether the TS action statements are being met, and whether TS requirements and license conditions are being met. Review visible portions of radiation monitor indications that could provide indication of an apparent uncontrolled release. Review control room logs and equipment out-of-service or clearance logs and verify that these logs appropriately reflect the plant status observed during the control board walkdown. Ensure that control room operators can explain lit annunciators. Verify that alarms with multiple inputs have a reflash capability to preclude masking a potential degraded condition. Verify that operators implement appropriate compensatory measures for inoperable alarms or alarms without reflash capability.

Pay attention to what's different day to day. Compare unit to unit.

Containment Conditions

Due to the inaccessibility during power operation, the containment provides a wealth of opportunities for inspectors during refueling or maintenance outages when the containment is open for inspection. Inspectors should take full advantage of this opportunity, if time and radiation conditions permit. Specific containment-related items that may be reviewed are as follows:

Fibrous Material: Verify when the containment is closed after outage activities that fibrous material and other materials that could threaten the operability of the containment sump or other mitigating systems have been removed.

Coatings: Like fibrous material, containment coatings such as paint have been known to peel or chip and threaten the operability of the containment sump or other mitigating systems.

During a containment tour, look for this condition and verify that containment coating issues are identified and resolved prior to containment closeout.

Other Foreign Material: Verify that other foreign materials such as plastic tie-wraps, duct tape, rope, flashlights, paper, loose insulation, loose insulation covering, plastic sheeting, and tools that could migrate to the sump during design basis accident conditions have been removed prior to final containment closeout.

Nothing substitutes for "being there." You have to climb, look at things and get dirty.

Containment Air Lock Closure Capability: Most plants are required to be able to expeditiously isolate containment under certain conditions during outage activities. Verify that this capability, if required, is maintained through the use of quick disconnect hoses through containment air locks.

Sump Screens: One of the most vulnerable passive systems in the containment is the containment sump. Sump screens are required to prevent material of a certain size from entering the sump area. This is most commonly accomplished through the use of a screen material around the sump. Routinely confirm that the sump screen has no obvious defects and is intact with no gaps. Verify that no bypass paths around the sump screen exist that could allow debris larger than the sump screen mesh size to enter the sump.

Structures Near the Containment Wall: At some facilities, structures such as floor grating and scaffolding are required to be maintained greater than some minimal distance from the containment wall to ensure that the integrity of the containment is maintained during a design basis or seismic event. Question the presence of permanent structures in close proximity to the containment wall.

External Event Related Issues

Flooding Flooding due to external and internal causes has been shown to be a significant contributor to risk at some facilities. Flooding has the potential to render multiple trains of equipment and support equipment inoperable which would result in a significant increase in plant risk. Flooding can also prevent or limit operator mitigation and recovery actions.

Assess the material condition of passive flood protection systems and features during routine plant entries. Look at the following features:

- Sealing of equipment below the floodline, such as electrical conduits,
- Holes or unsealed penetrations in floors and walls between flood areas,
- Physical condition of flooding barriers, such as expansion joints for piping that penetrates safety-related equipment room ceilings and walls,
- Adequacy of watertight doors between flood areas, including door seals,
- Operable sump pumps, level alarms, and control circuits, and
- Unsealed concrete floor cracks.

Note whether flood barriers around a room have been removed for maintenance activities and what compensatory measures have been established.

When screening corrective action reports, keep a list of items to follow up on during subsequent plant tours.

Cold Weather: Icing and freezing from extreme cold weather conditions is a common-cause failure mechanism that can quickly affect a variety of systems unless mitigating actions are promptly taken. Extreme cold weather conditions can affect intake structures, process lines, emergency diesel generator oil and grease viscosities, essential chillers, electrical systems, and heating, ventilation, and air conditioning systems. Lack of proper design, incomplete review of operating experience, and insufficient attention to cold weather preparations are responsible for many events that occur. Be aware of the potential for equipment problems during cold weather conditions and inspect systems potentially affected during cold weather conditions to ensure that these systems remain operable. Review the licensee's methods for verifying proper operation of heat trace freeze protection circuits. During periods of cold weather, check the condition of insulation for exposed instrument sensing lines for equipment such as the secondary PORVs. Relatively small gaps in the insulation can cause the line to the controller to freeze and result in intermittent lifting or failure of the valve.

High Winds: High winds can present a hazard to the plant if equipment in proximity to the switchyard is not properly controlled. Verify that all loose metal objects, such as sheet metal or other metallic material that could present a shorting hazard to breakers, transformers, and other electrical equipment, are properly controlled in the event of a tornado or other high wind conditions.

Fire Protection

Fire can be a significant contributor to reactor plant risk. The fire protection program extends the concept of defense-in-depth to fire protection in plant areas important to safety by preventing fires from starting; rapidly detecting, controlling, and extinguishing those fires that do occur; and providing protection for structures, systems, and components (SSCs) important to safety so that a fire that is not promptly extinguished by fire suppression activities will not prevent the safe shutdown of the reactor.

Assess the material condition of active and passive fire protection systems and features, their operational lineup, and operational effectiveness during routine plant entries. The following items can be verified during these entries.

Control of Transient Combustibles and Ignition Sources: Observe if transient combustible materials are in the area. If transient combustibles are observed, verify that they are controlled in accordance with licensee administrative procedures.

You must remain aware of operating experience (OE). Frequently review value added findings. Communicate your questions and issues.

Control of Hotwork: Observe if any welding, grinding, brazing, or flame cutting is being performed in the area. Verify that for all hotwork being performed, a dedicated fire watch with a dedicated fire extinguisher is available to extinguish a fire, in accordance with licensee procedures. In general, this dedicated fire watch should not be engaged in any other activities and should remain posted for at least 30 minutes after the hotwork is complete.

Fire Suppression Systems: Verify by visual observation that sprinkler heads are not obstructed by overhead equipment and that water supply valves are open and the fire water supply and pumping capability is available. Observe any material condition issues that may affect performance of the system, such as mechanical damage, painted sprinkler heads, or corrosion. For gaseous suppression systems such as halon or carbon dioxide, verify that nozzles are not obstructed or blocked by plant equipment such that gas dispersal would be impeded. For gaseous systems, verify the vent piping off the bottles is piped correctly (compare bottles). Verify that the suppression agent charge pressure is within the normal operating band and that supply valves are open as required. Observe any material condition that may affect the performance of the system, such as mechanical damage, corrosion, damage to doors or dampers, open penetrations (open floor drains may preclude proper gaseous concentration following actuation), or nozzles blocked by plant equipment.

Manual Fire Fighting Equipment: Verify that the access to portable fire extinguishers is not obstructed by plant equipment or work activities. Verify that the general condition of the fire extinguishers is satisfactory. Verify that the pressure gauge reads in the acceptable range, that nozzles are clear and unobstructed, and that charge test records indicate that testing has been accomplished within the required periodicity. Verify that fire extinguishers are in good material condition. Verify that fire extinguishers are not corroded by feeling all surfaces, including the underside, for evidence of rust.

Fire Hose Stations and Standpipes: Verify that the general condition of fire hose stations is satisfactory. Verify that the fire hose is in satisfactory material condition, that the fire hose nozzle is not mechanically damaged and is correct for the application, that valve handwheels are in place, that the fire hose reel is correctly mounted to the fire hose standpipe and has free movement and not otherwise obstructed by plant equipment, that a spanner wrench is in close proximity to the fire hose station to aid in the operation of the isolation valves, and that the seal to prevent the reel from unwinding, if required, is properly wired in place when not in use.

Fire Doors: Observe the material condition of the fire doors in the area being accessed. Verify that the doors are not being propped open without required impairment permits and that the door latching hardware functions properly. Verify that the doors are properly closed when not in use. Caution: a fire door impairment (and periodic fire watch compensatory measures) may not be sufficient for a multi-purpose door (fire/HELB/flood protection watertight).

Electrical Raceway Fire Barrier Devices: Observe the material condition of electrical raceway fire barriers such as cable tray fire wraps and verify that no cracks, gouges, holes, rips, or gaps exist that could compromise the ability of the material to function properly.

Focus on changes, decisions, and adjustments made in-process or with short lead times.

Ventilation System Fire Dampers: Observe the material condition of fire dampers and verify that fusible links are in place and appear to be in good physical condition.

Fire Proofing: Observe the material condition of fire-proofing materials and verify that the material is installed with all areas uniformly covered with no bare areas.

Fire Barrier and Fire Area/Room/Zone Electrical Penetration Seals: Observe accessible electrical and piping penetrations and verify that seals are properly installed and in good condition. Verify that core bores (holes) drilled through concrete for the passage of electrical cables between fire zones are properly sealed with fire retarding material.

Roll-up Fire Doors: Verify that no objects or debris are in the path that would prevent the door from closing freely when needed (actuated).

Emergency Lighting: Verify that emergency lighting unit batteries are being properly maintained by observing the unit's lamp or meter charge rate indication and specific gravity indication. An emergency lighting unit that is continuously on fast charge is a potential indication of a failed battery. Look for other potential problems such as dirty emergency lighting lamps that decrease the output of the emergency lights, lights that are improperly aimed, and loose lamp pivot connections that result in incorrectly aimed lights.

Smoke Detectors: Verify that smoke detectors are installed near the ceiling and that if beam pockets are larger than 8 feet on center, a separate smoke detector is installed in each beam pocket.

Electrical Separation Criteria: Verify that temporary electrical cables or extension cords are not draped over or tie-wrapped to safety-related conduits or near safety-related cable trays.

Epoxy Coatings: If not properly procured and applied, epoxy floor coatings can, under certain circumstances, represent a significant and unanticipated fire load. Verify that these coatings do not exceed more than about 1/8-inch in thickness and bring any discrepancies to the attention of licensee personnel.

Space Heaters: Space heaters are commonly used during the winter. Verify that licensees have considered the following items before placing space heaters in service: (1) fire hazards or combustibles near the space heater; (2) damage to or effect on the operability of equipment; and (3) the effect of accelerated aging on the environmental qualification of electrical equipment.

When emergent issues arise, walk down the issue in the field if accessible. Follow up periodically until the issue is resolved to ensure conditions do not degrade further.

Security Issues

Inspectors have numerous opportunities to observe security personnel and licensee security measures during inspections and should take advantage of these opportunities to assess the security program. Most inspectors are not security experts, but common sense and alertness can enable an inspector to assess the effectiveness of a licensee's security organization. During daily in-processing prior to entering the plant protected area, look at security personnel operating equipment such as explosive detectors and metal detectors, and observe their response to alarms and other unusual situations. Observe security force personnel in the field and verify that they are performing their duties in a professional manner.

> ***Note: Under no circumstance should an inspector "test" the effectiveness of a licensee's security staff by any means, such as intentionally causing the actuation of a security alarm.***

Occupational Safety

Memoranda of Understanding (MOUs) dated October 21, 1988, and July 26, 1996, between the U.S. Nuclear Regulatory Commission and the Occupational Safety and Health Administration (OSHA) provide for inspector involvement, during inspections of operating reactors, in the identification and disposition of safety concerns. Notify licensee management and, as appropriate, the NRC Regional Office OSHA Liaison Officer of non-radiological hazards personally observed or reported by licensee employees.

The following specific areas should be routinely observed during an inspection of in-plant activities:

Personal Protective Equipment: Verify personnel are wearing all required Personal Protective Equipment (PPE) such as hearing protection, eye protection, and head protection. Additional protection may be required based on local conditions, such as "double hearing protection" in designated areas, such as in the emergency diesel generator rooms during emergency diesel generator testing; the use of a lanyard with a "break-away" feature for the display of identification badges and dosimetry; tucking in of neckties and any other loose clothing in the vicinity of rotating equipment; and footwear that is in good condition and protects against injury due to falling objects.

Fall-Related Injuries: Safety reports indicate that the most frequently treated injuries at nuclear plants are those resulting from falls and tripping. Verify that permanent ladders firmly attached to anchor points are sturdy and do not wobble. Verify that licensee personnel using moveable ladders do so in a safe manner. A ladder tender helps avoid a fall. No one should ever stand on the top step of a ladder. Another area of concern involving ladders can occur when personnel attempt to carry items with them when climbing up or down a ladder. Be aware of this when walking to/from an activity and ensure that no one is carrying more than what is safe. Verify that workers use safety harnesses, when required, to prevent a fall.

Electrical Shock: Electrical shock most commonly occurs from working on open wires while components are energized and from the use of unsafe extension cords and temporary service leads. Verify that this work is done in a safe manner using appropriate equipment.

Heat Stress Awareness: Some areas of nuclear power plants may have high heat and humidity levels due to operating equipment, steam lines, and limited ventilation. Verify that licensee personnel have taken adequate precautions to protect workers from heat-related stress.

Confined Space Entry: Environments in which the oxygen levels are limited or unknown are considered to be confined space areas of which their entry is required to be strictly controlled. Verify that personnel accessing these areas are qualified, that a confined space entry permit has been obtained and posted, and that other confined space entry requirements are met.

Diving Activities: Diving accidents have resulted in fatalities at nuclear plants. Ensure these activities are being accomplished safely. Verify that control room personnel are aware that diving activities are occurring and that controls are in place to prevent energizing rotating equipment in the vicinity of the divers. Each diver should have a diving tender who can quickly respond to an unexpected situation.

Smoking Area Locations: Verify that designated smoking areas are not near explosive tanks or other combustibles, such as hydrogen tanks.

Equipment Issues: Verify that personnel safety devices installed in the plant are in good material condition and that workers are not engaging in unsafe work practices that otherwise could be made safer with the installation of safety devices.

Lighting: Verify that areas routinely entered by plant personnel are sufficiently illuminated to avoid a fall or other injury. For areas that are not routinely accessed, verify that personnel are using flashlights or other temporary lighting.

Scaffolding: Temporary scaffolding can present a number of personnel safety issues if not erected properly. Verify that the scaffolding has toe-boards to prevent tools and other heavy objects from accidently being kicked off the scaffolding onto someone below. Verify that the general condition of the scaffolding is good. Always verify that a scaffold tag is in place and that the scaffolding has been reviewed and approved.

Compressed Gas Cylinder Storage: Due to their relatively high center of gravity when in the upright position, compressed gas cylinders can cause a worker injury if not properly stored. Verify that these cylinders are capped and controlled to prevent them from falling over. A punctured cylinder or broken valve can become a missile hazard when the compressed gas discharges.

Access Controls to High Radiation Areas and Locked High Radiation Areas

In general, areas with radiation levels of greater than 1 rem/hr must be controlled by a locked door and areas greater than 100 mrem/hr and less than 1 Rem/hr must be controlled through some type of barricading device, such as a door or swing gate. Verify doors or other barriers to these areas are properly controlled. Verify that walls or other barriers, such as fences, do not have openings and are of sufficient height so that an individual can not easily enter the area.

USEFUL INSPECTION TIPS

Knowledge Is Power

Know what ventilation systems are critical support equipment such as those for EDGs and under what conditions they are critical, i.e. environmental conditions. For example, the number of ventilation fans required to be functioning may change based on outside temperatures.

Know the basic values of key design information for the site. Know the site flooding elevation, electrical separation criteria between trains, where design ventilation boundaries are assumed, etc. Being familiar with these types of design information will enable you to identify problems, even if you do not understand the work in progress. Summary sheets for this type of information could be made up for your site, sort of a short focus briefing for each visiting inspector.

Be familiar with the site's color coding for safety-train and instrumentation channel conduit and cabling.

Residents should understand a licensee's security defensive strategy so when touring the plant you can observe whether you think there are any vulnerabilities. Residents, who have a high level of integrated plant knowledge, should work with security inspectors to identify potential vulnerabilities.

Remain generally knowledgeable of the medical restrictions placed on operator licenses.

A measure of a licensee's commitment to quality and safety can be determined by analyzing the effectiveness and support of the licensee's QA program. Good licensees have aggressive QA programs and management that fully supports their proper implementation. It is very important to understand QA concepts and how QA systems work.

Learn To Listen, Listen To Learn

Learn to listen. Every person you meet in the field knows something about the plant that you don't; find out what it is.

When gathering information by talking with plant personnel, remember the saying "trust but verify." Remember that different doesn't necessarily mean wrong, so don't use another plant as the regulatory standard.

Never underestimate the potential for miscommunication. Try to corroborate interviews.

Be tactful - you want people to talk to you. Listen to what people say, regardless of their position. Janitors, craftsmen, technicians and secretaries can all provide useful information.

Be approachable. If people feel intimidated by you, they are far less likely to talk to you.

Be professional. Build trust with the licensee. Trust but verify!

Listen, Listen, Listen - Workers will tell you where to look in general conversation without making an allegation, just listen.

Always check when engineering says operations verifies something.

Get to know the operators and maintenance technicians so they are comfortable in your presence. They'll give you a lot of food for thought.

Ask the same questions of several different people or several different levels of the licensee organization involved in the same issue; then compare answers.

Engineers, planners, and mechanics do not always have the same understanding of "skill of the craft." For example, engineers and planners sometimes expect the mechanic to go to the technical manual to determine if bolts need torquing, and if so to what tightness. The mechanics may follow training which states that if the work package doesn't call for torquing, it only gets wrench tightened. The same problem occurs with thread locking compounds.

Wear Out, Don't Rust Out

During operation/surveillance testing of EDGs during hot summer ambient conditions, check the operational limits for the scavenging/intake air against the vendor thresholds for de-rating the EDG. This is particularly important if there is minimal margin between the EDG output and the required emergency loads.

Non-routine tasks and restoration from modifications or maintenance are always good inspection opportunities.

Review the control room narrative log and follow up with field verification.

Stay current on operating experience, operability determinations, risk-informed operator actions, SERs and licensee commitments that can be verified in the field.

You can get a lot of good leads from attending the daily reactor operators brief in the control room.

Tour remote locations.

Spend time with other inspectors in the plant. Two sets of eyes and two questioning minds are better than one.

Make it a habit to occasionally tour the plant with other inspectors (other residents or visiting inspectors), it's a win-win, almost everyone can learn something.

Be Insatiably Curious

Ask "why" a lot. Use a questioning attitude.

Pick an item of which you are not sure of its function and take a few minutes to familiarize yourself with it. Then ask yourself whether what appears to be its function matches with your training or understanding of the plant. If not, or you are unsure, make a note to look at the FSAR when you return to the office.

Question the adequacy of software which performs safety functions.

When reviewing engineering and technical work, question anything that doesn't comport with your BWR/PWR training.

Maintain a questioning attitude about licensee equipment and actions that could impact the ability of safety-related equipment to fulfill its design basis functions (periodic calibration or preventive maintenance performed? Timely? Appropriate?).

Make sure that your field observations align with the design basis and good engineering judgment.

Don't Major in Minor Things

Note whether an area has more than one train of safety-related equipment. Areas that have more than one train are prime candidates for a fire protection inspection. If the area has more than one train, check the IPE for the risk importance of the area when you get back to the office.

Review pending licensing actions that may impact the current design basis of the plant.

For visiting regional specialists, going over the inspection procedure with the licensee well ahead of the inspection allows the licensee to prepare a package and helps to knock off the relatively basic issues early in the inspection. This allows the inspector to effectively use their time to look at the more risk significant issues.

Go back to the basis documents. What was this thing designed to do? What will it do?

The Devil Is in the Details

Closely review licensee contingency plans for risk mitigation. Don't just look at the plan. Pick several actions - will the components be accessible, are special tools necessary, are the tools prestaged, are the personnel trained to perform the task?

Question licensee investigation of identified problems. Resolution of one issue may leave closely related issues overlooked.

Verify that vendor information is being properly considered in technical issues and maintenance activities. Occasionally things are not maintained or implemented as designed.

Use your knowledge of the expected plant response and the plant design to question discrepancies overlooked by licensee personnel. This also applies in the simulator and for procedure deficiencies.

Use the Dynamic Web Site to do key word searches for an area you are inspecting. Put in dates for the beginning of the ROP (4/1/98) to the current date and find all NCVs for a particular subject. It can be used by new inspectors to key into problems that have occurred in the past. You can also sort by inspection procedure.

Always bring the basics with you when you go out into the plant: a flashlight, a notebook, and a pen.

Remember, OSHA regulations apply to you too! Wear your eye, ear, and feet protection.

Keep a low threshold, and do not easily let the licensee "explain it away." If it does not seem right...it probably isn't.

Gather plant status information from a variety of sources. Things should fit together. Explore disconnects.

Accompany the system engineer on a system walkdown. You get a feel for how often he/she actually looks at the system and whether he/she has surfaced all the real issues. Written notes from past walkdowns can be very enlightening.

Several plants, in the interest of ALARA, have been using video surveillance systems in lieu of more extensive operator rounds. It is useful to request entry into those areas and you'll generally find that you can't see everything (and every area) from the camera.

When issues surface during surveillance testing or are self-revealing in nature, ask yourself if there was some precursor or tell-tale aspect that could have allowed you to identify the issue sooner.

Engage control room personnel by discussing observations.

No Time To Lose
You don't have time to learn all of the industry's lessons through your own experiences. You must remain aware of operating experience (OE). Frequently review the value added findings on the DRP Web pages. Discuss your questions and issues with other inspectors (at other sites and within DRS). Use the value added findings list to see what techniques have worked for others.

Take notes. Include the FSAR and NRC SERs in your verification sources. If you can't find a requirement for something you think may be a problem, consult the Standard Review Plan (SRP) (NUREG-0800). The SRP will indicate what codes, standards, CFR section, Reg. Guides, etc. the staff uses to compare the licensee's design and operating principles against. The licensee's NRC approved QA plan is another source, which implements 10CFR 50 Appendix B, the fire protection QA plan, and other QA requirements, and lists applicable standards and Reg. Guides. Don 't be embarrassed to ask experienced inspectors what they think of whatever you observed (you may want to look at the FSAR first).

Make use of NRC Operating Experience. Consider creating a notebook including inspection procedure (i.e, 71111.04, Equipment Alignment, etc.), the NRC findings and NCVs issued in the last 2 years. This helps maintain consistency and also it provides information on the type of findings that others inspectors are identifying. Consider developing a tool box for every inspection procedure with a listing of applicable information such as TS/UFSAR/Applicable Licensee Procedures, etc.

Review the inspection history for your facility (sometimes issues have a way of coming back around).

Read about other plant's problems. Look for similarities.

Discuss technical issues with regional specialists.

Talk with the other resident everyday about what you saw and heard.

There Are No Challenges, Only Opportunities

Don't just focus on the root cause of an event. Think of the event in an integrated fashion - did everything function as per design?

Always maintain a questioning attitude. Never assume that a problem has been identified and addressed, no matter how obvious. Ask open-ended questions (e.g. what can you tell me about this?).

Tour the plant slowly and look for unusual plant conditions. If you are new to a facility it is not always easy to know what constitutes a "normal" situation or configuration. One method to determine whether a piece of equipment is in a normal configuration or whether a situation is acceptable is to compare the identified configuration or condition to a redundant piece of equipment or area.

While conducting a routine inspection, use that opportunity to inspect other aspects of the licensee's facility.

Always keep in mind the integrated effect of plant problems on plant safety.

INDEX OF TOPICS

NOTES

NOTES

NRC acknowledges the efforts of the Inspector Field Observation Best Practices Team for sharing their experience and knowledge with all inspectors.

Joseph G. Schoppy, RI, Division of Reactor Safety, Senior Reactor Inspector
Malcolm T. Widmann, RII, Division of Reactor Projects, Branch Chief
Eric R. Duncan, RIII, Division of Reactor Projects, Branch Chief
Mark Shaffer, RIV, Division of Nuclear Material Safety & Safeguards, Branch Chief
Lois M. James, Nuclear Reactor Regulation, Reactor Operations Engineer
Fiona T. Tobler, Nuclear Reactor Regulation, Senior Program Analyst

INSPECTIONS TIPS

Stop - Look - Listen - Learn Stop and stand in an area for 5 to 15 minutes. It's amazing what will stand out or who will walk by with an interesting story.

Get out in the field, especially during testing and outages. When you know what "normal" looks like, "abnormal" will jump out at you.

When screening corrective action reports, keep a list of items to follow up on during subsequent plant tours.

When emergent issues arise, walk down the issue in the field if accessible. Follow up periodically until the issue is resolved to ensure conditions do not degrade further.

Watch for and take advantage of opportunities to tour normally inaccessible areas.

Nothing substitutes for "being there." You have to climb, look at things and get dirty.

Follow the string, extension cord, temporary label, or anything out of the ordinary. There's usually a story.

You must remain aware of operating experience (OE). Frequently review value added findings. Communicate your questions and issues.

Pay attention to what's different day to day. Compare unit to unit.

Focus on changes, decisions, and adjustments made in-process or with short lead times.

Suggestions for Improvements

Please email comments, suggestions for improvement, and/or your best practices relative to field observations to: **PIPBCAL**

NUREG/BR-0326
November 2005

RN0109

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
REGION IV VISIT
August 14, 2007

-AGENDA-

Time	Topic	Presenter	Time Allotted
8:30 - 9:00 am	Region IV Overview and Challenges	Dr. Mallett P. Gwynn	30 minutes
9:00 - 9:30	Knowledge Management	J. Lopez R. Caniano	30 minutes
9:30 - 9:50	Reactor Oversight Process (ROP) Case Study #1	J. Hanna	20 minutes
9:50 - 10:10	ROP Best Practices	M. Hay	20 minutes
10:10 - 10:20	BREAK	-	10 minutes
10:20 - 10:40	ROP Case Study #2	W. Walker	20 minutes
10:40 - 11:10	ROP Case Study #3	G. Warnick	30 minutes
11:10 - 12:10	LUNCH	-	1 hour
12:10 - 12:40 pm	Incident Response Center Tour	L. Howell	30 minutes
12:40 - 1:05	Independent Spent Fuel Storage Installations and Decommissioning	Dr. Spitzberg	25 minutes
1:05 - 1:35	Safety Culture	L. Smith R. Caniano	30 minutes
1:35 - 2:05	Component Design Basis Inspections	G. Replogle	30 minutes
2:05 - 2:20	BREAK	-	15 minutes
2:20 - 3:30	ROP Roundtable Discussion ACRS Questions and Answers	T. Gody K. Clayton P. Elkmann G. Warnick G. Replogle D. Loveless J. Drake	1 hour 10 minutes
3:30 - 3:50	Closing Remarks	Dr. Mallett P. Gwynn	20 minutes

RIV CONTACT: Brian Tindell, bwt@nrc.gov or (817) 860-8244
ACRS CONTACT: Michael Junge, mxj2@nrc.gov or (301) 415-6855

Résumés of SONGS Resident Inspectors

<u>Clyde Osterholtz, Senior Resident Inspector</u>

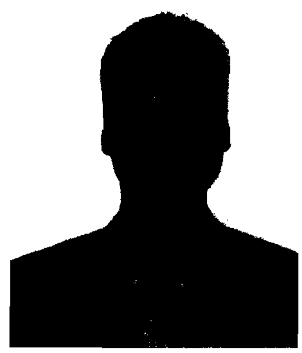
Mr. Osterholtz has been the Senior Resident Inspector at San Onofre since May 2001. Prior to joining the NRC, Mr. Osterholtz served in the United States Navy Submarine Service as an electronics technician and reactor operator from 1980 to 1986. Mr. Osterholtz graduated from The Ohio State University in 1990 with a Bachelor of Science degree in Engineering Physics/Nuclear Engineering, and joined the NRC in September 1990 as a licensing examiner in the Division of Reactor Safety in Region III. In 1996, he was selected as Resident Inspector at Ginna Nuclear Generating Station in the Division of Reactor Projects in Region I.

Mr. Osterholtz transferred to the resident inspector position at the Fort Calhoun Generating Station in the Division of Reactor Projects in Region IV in 2000, and was selected for the Senior Resident Inspector position at San Onofre in October of that same year.

Mr. Osterholtz has led or participated in numerous team inspections throughout his career, including leading a special inspection in response to a breaker fire at San Onofre in February 2001.

<u>Mark Sitek, Resident Inspector</u>

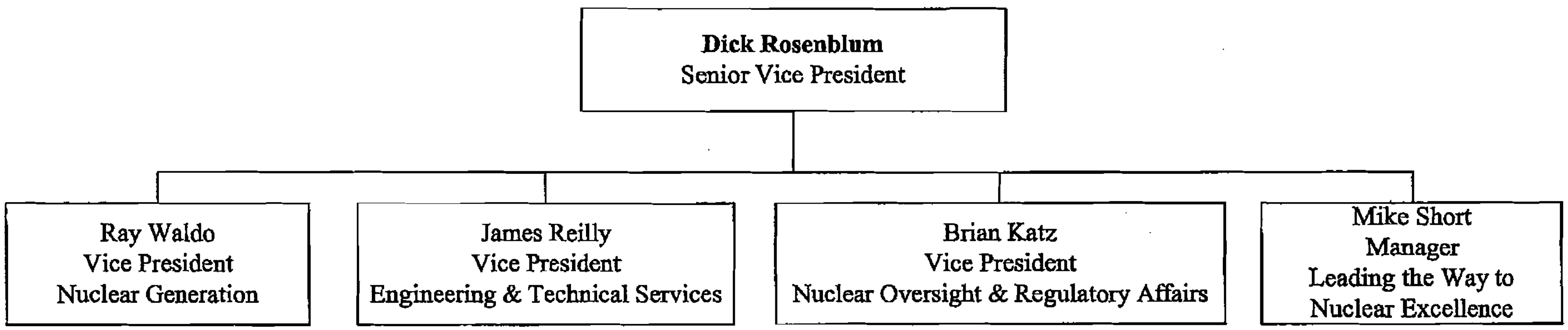
Mark Sitek is the Resident Inspector at San Onofre Nuclear Generating Station. Mr. Sitek joined the agency through the NRC's Graduate Fellowship Program in June 1996. He entered the program following completion of his Bachelor of Science in Nuclear Engineering from Rensselaer Polytechnic Institute in 1996. Mr. Sitek began his NRC career in the then Office of Nuclear Materials Safety and Safeguards (NMSS), Division of Industrial and Medical Nuclear Safety as a general engineer.



In August 1997, Mr. Sitek returned to school as part of the fellowship program where he earned a Master of Science in Nuclear Engineering from the Massachusetts Institute of Technology in September 1999. Following graduate school, he returned to NMSS in February 2000 as a health physicist where he completed a rotational assignment to Region I and qualified as a materials health physics inspector.

Mr. Sitek became the Resident Inspector at San Onofre in May 2002. Since that time, he has completed rotational assignments as Senior Resident Inspector at Grand Gulf Nuclear Station and as Team Leader, Technical Support Staff in Region IV.

Nuclear Organization



NUCLEAR GENERATION
AS OF JUNE 30, 2007

Figures are Budget / Actual

RAY WALDO
Vice President,
Nuclear Generation

Total SCE	824	759
Mgmt		321
Operative		501
SCE PT/Temp	1	5
Agency/Contract	172	214

TED VOGT
Special Projects

Staffing Pipeline = 5
(not counted)

Kimberly Mendicelli
Executive Assistant

OSCAR FLORES
Manager,
Chemistry

Total SCE	39	37
Mgmt		20
Operative		22
SCE PT/Temp	0	0
Agency/Contract	0	0

TOM YACKLE
Manager,
Operations

Total SCE	240	230
Mgmt		73
Operative		157
SCE PT/Temp	0	0
Agency/Contract	0	0

ROBERT CORBETT
Manager,
Health Physics

Total SCE	93	84
Mgmt		36
Operative		56
SCE PT/Temp	0	1
Agency/Contract	66	64

TODD ADLER
Manager,
Work Control

Total SCE	30	29
Mgmt		29
Operative		0
SCE PT/Temp	0	0
Agency/Contract	0	1

JOHN HIRSH
Manager,
Maintenance & Construction Services

Total SCE	419	376
Mgmt		160
Operative		266
SCE PT/Temp	1	4
Agency/Contract	106	149

20020
SRO Training
Bates, Al
Bohrisch, Robert
Bosch, Lou
Herschthal, Mark
Murray, Joel

ENGINEERING & TECHNICAL SERVICES
AS OF JUNE 30, 2007

Figures are Budget/Actual

JAMES REILLY
Vice President,
Engineering & Technical Services

	Budget	Actual
Total SCE	559	550
Mgmt		496
Operative		54
SCE PT/Temp	4	9
Agency/Contract	82	113

DAN BREIG
Deputy

Mariane Sanchez
Executive Assistant

HOWARD NEWTON
Manager,
Site Support Services

	Budget	Actual
Total SCE	75	77
Mgmt		50
Operative		27
SCE PT/Temp	2	2
Agency/Contract	48	59

OWEN THOMSEN
Manager,
Nuclear Fuel Management

	Budget	Actual
Total SCE	34	34
Mgmt		34
Operative		0
SCE PT/Temp	2	1
Agency/Contract	0	0

KEN JOHNSON
Manager ,
Design Engineering Organization

	Budget	Actual
Total SCE	165	152
Mgmt		152
Operative		0
SCE PT/Temp	0	4
Agency/Contract	12	16

JOHN FEE
Manager,
Site Emergency Preparedness

	Budget	Actual
Total SCE	49	50
Mgmt		32
Operative		18
SCE PT/Temp	0	0
Agency/Contract	16	14

RICH ST. ONGE
Manager,
Maintenance / System Engineering

	Budget	Actual
Total SCE	136	139
Mgmt		130
Operative		9
SCE PT/Temp	0	2
Agency/Contract	0	0

RON ELSASSER
Manager,
Nuclear Training

	Budget	Actual
Total SCE	69	67
Mgmt		67
Operative		0
SCE PT/Temp	0	0
Agency/Contract	4	3

JORGE MORALES
Manager,
Projects

	Budget	Actual
Total SCE	26	26
Mgmt		26
Operative		0
SCE PT/Temp	0	0
Agency/Contract	1	20

MIKE WHARTON
Manager,
Strategic Issues Project

	Budget	Actual
Total SCE	2	2
Mgmt		2
Operative		0
SCE PT/Temp	0	0
Agency/Contract	1	1

J0000
Cross, Glenn (AC)
Mihalik, Mark

(*) = Loaned from other depts (not counted)
(1) = Loaned to March to Excellence (counted)

NUCLEAR OVERSIGHT & REGULATORY AFFAIRS
AS OF JUNE 30, 2007

Figures are Budget/Actual

* = Security not included in totals

BRIAN KATZ
Vice President,
Nuclear Oversight & Regulatory Affairs

Total SCE	385	375
Mgmt		165
Operative		210
SCE PT/Temp	12	14
Agency/Contract	26	24

MARC GOETTEL
Process Integration
(not counted)

Dawn Farrell
Executive Assistant

JOSE PEREZ
Manager,
Business Planning & Financial Services

Total SCE	40	38
Mgmt		38
Operative		0
SCE PT/Temp	1	1
Agency/Contract	17	15

GARY ZWISSLER
Manager,
Business Administration

Total SCE	158	156
Mgmt		23
Operative		133
SCE PT/Temp	6	7
Agency/Contract	1	0

CAROLINE McANDREWS
Manager,
Nuclear Oversight & Assessment

Total SCE	71	73
Mgmt		73
Operative		0
SCE PT/Temp	0	1
Agency/Contract	2	4

BRIAN CONWAY
Manager,
Staffing Pipeline

Total SCE	87	82
Mgmt		5
Operative		77
SCE PT/Temp	5	5
Agency/Contract	5	5

JOHN TODD
Manager,
Site Security

Total SCE	438	456
Mgmt		
Operational Support		
SCE PT/Temp	0	0
Agency/Contract	1	0

A. E. SCHERER
Manager,
Nuclear Regulatory Affairs

Total SCE	23	19
Mgmt		19
Operative		0
SCE PT/Temp	0	0
Agency/Contract	0	1

WILLIS FRICK
Manager,
Nuclear Safety Concerns

Total SCE	4	5
Mgmt		5
Operative		0
SCE PT/Temp	0	0
Agency/Contract	0	0

V0000
Baker, Randy (V1000)
Giroux, Richard
Green, Laura
Morris, William

Figures are Budget/Actual

LEADING THE WAY TO NUCLEAR EXCELLENCE
AS OF JUNE 30, 2007

MIKE SHORT
Manager,
Leading the Way to Nuclear Excellence

Total SCE	50	41
Mgmt		41
Operative		0
SCE PT/Temp	0	0
Agency/Contract	1	1

Ami Dominguez
(Matrixed)

AOR: 3766 PR # 221 DEPT ID: 03503

- MARTY COOPER (1)
- RON GEORGE (AC)
- MARK PRICE
- STEVE ROOT
- Nuc Regulatory Affairs = 1
  Security = 37

(1) = Loaned from OPS (not counted)

Legend

(AC) = Agency / Contract

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Richard M. Rosenblum

Senior Vice President of Generation and Chief Nuclear Officer
Southern California Edison

Richard M. Rosenblum is senior vice president of Generation and chief nuclear officer for Southern California Edison (SCE), responsible for all power generating facilities, including nuclear and related fuel supplies. He was appointed to his current role in November 2005.

Previously he was senior vice president of the Transmission and Distribution business unit which is responsible for the high-voltage bulk transmission and retail distribution of electricity in SCE's 50,000-square-mile service territory. He assumed that position in February 1998.

Rosenblum began his career at SCE in 1976 as an engineer working at the company's San Onofre Nuclear Generating Station (SONGS). He held various positions in the company's Nuclear Department, including startup manager, station technical manager, nuclear oversight manager, and nuclear regulatory affairs manager. He was elected vice president of Engineering and Technical Services in 1993. In that role he was responsible for engineering construction, safety oversight, and other engineering support activities at SONGS.

In January 1996, he was appointed vice president of the Distribution business unit, which is responsible for providing electric service to SCE's 4.6 million customers.

Rosenblum earned a B.S. and M.S. in nuclear engineering from Rensselaer Polytechnic University.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Raymond W. Waldo

Vice President, Nuclear Generation
Southern California Edison

Raymond Waldo is vice president of Nuclear Generation for Southern California Edison (SCE). Elected to that position on January 1, 2005, he is responsible for the daily operation of the San Onofre Nuclear Generating Station.

Previously, Waldo was the station manager at San Onofre, in charge of operations, maintenance, work control, health physics, chemistry, and training for that facility.

Waldo began his career with SCE in 1980 as a station engineer at San Onofre. He held several engineering and supervisory positions and became the operations manager in 1990 and station manager in 2002.

Before joining SCE, he served in the Peace Corps and was a supervisor at the Livermore Pool Type Reactor at the Lawrence Livermore National Laboratory.

Waldo earned a bachelor's degree in physics from Caltech and a master's degree and doctorate in nuclear engineering from Georgia Tech. He also earned a Senior Reactor Operator license on San Onofre Units 2 and 3 from the Nuclear Regulatory Commission in 1983.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

James T. Reilly

Vice President, Nuclear Engineering and Technical Services
Southern California Edison

James Reilly, as vice president of Nuclear Engineering and Technical Services, is responsible for engineering, construction, project management, and decommissioning activities at the San Onofre Nuclear Generating Station (SONGS). He was elected vice president in December 2005.

Previously, Reilly was director of Engineering and Technical Services at SONGS, responsible for SONGS engineering organizations, nuclear fuel management, Unit 1 decommissioning services, and site facilities.

Reilly began his Edison career in 1979 as an engineer at San Onofre Unit 1, and held various positions in the company's Nuclear Department, including supevisor and station technical manager. In addition, he was vice president of operations at Edison Technology Solutions; manager of Engineering, Construction and Fuel Services; and manager of Research & Technology Applications.

Before joining Edison, Reilly was a senior engineer at General Atomics and a manufacturing engineer at both General Electric and Swanson Engineering and Manufacturing Company.

Reilly holds a Bachelor of Science degree in mechanical engineering from the University of Redlands and a Master of Science degree in nuclear engineering from the University of California, Los Angeles.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Brian Katz

Vice President, Nuclear Oversight and Regulatory Affairs
Southern California Edison

As vice president of nuclear oversight and regulatory affairs for Southern California Edison, Brian Katz is responsible for the company's nuclear safety and quality programs and interactions with the Nuclear Regulatory Commission.
He manages business planning and budgeting, including nuclear-related California Public Utilities Commission regulatory activities. He is also responsible for co-owner relationships for the San Onofre and Palo Verde nuclear power facilities, as well as management of the security operations.

Prior to his election as vice president in 2005, Katz was manager of the Generation Business Planning and Strategy organization. Having held that position since 1999, he was responsible for managing regulatory, business, and strategic issues, including developing and implementing a business/regulatory restructuring strategy for Edison's nuclear and non-nuclear generation business.

Katz began his Edison career in 1974 as a nuclear systems engineer and held several key management positions within the Nuclear organization.

Before joining Edison, he worked for Metcalf and Eddy Consulting Engineers. Prior to that, he worked for General Electric at the Knolls Atomic Power Laboratory in Schenectady, N.Y. as a reactor fluid systems engineer.

Katz holds a mechanical engineering degree from Pratt Institute, New York, a professional designation in Business Management from UCLA, a certificate in Project Management from UCI, and professional engineering licenses in mechanical and nuclear engineering.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Michael P. Short

Manager, Leading the Way to Nuclear Excellence
San Onofre Nuclear Generating Station

Michael P. Short, as Manager of Leading the Way to Nuclear Excellence, is responsible for the implementation of the San Onofre Nuclear Generating Station (SONGS) Strategic Plan including oversight, facilitation, and qualitative review of the initiates to improve performance at SONGS.

Previously, Short was Manager of Systems Engineering at SONGS, where he was responsible for organization and administration of long term strategies for each system to improve the overall system performance. In this capacity, he also managed special programs including Steam Generators, Flow Accelerated Corrosion, Inconel Nozzles, State of System Report, Operating Experience Reporting, Probabilistic Risk Assessment, Performance Indicators, and Maintenance Rule.

Short began his career with Southern California Edison in 1976 as a Plant Engineer at San Onofre Unit 1. During his 31 years experience at SONGS, Short has held various managerial positions including Supervisor of Shift Technical Advisors, Project Manager for SONGS Unit 1 Retrofit, Nuclear Training Manager, Design Basis Documentation Program Manager, Station Technical Manager, and Site Technical Services Manager.

Short holds a Bachelor of Science degree in Engineering from the University of California, Irvine.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Daniel P. Breig

Manager, Engineering Excellence
San Onofre Nuclear Generating Station

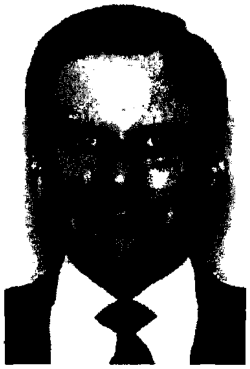
As Manager of Engineering Excellence of the San Onofre Nuclear Generating Station (SONGS), Daniel P. Breig is Assistant to the Vice President, E&TS, specifically focused on management and leadership of quality initiatives throughout the department. The primary function of the job is to create a continuous improving organization that establishes a reputation and performance level consistent with the best engineering organizations in the world.

Prior to being assigned duties as the Manager of Engineering Excellence in June 2007, Breig has held the San Onofre positions of Station Manager, Startup Manager, Project Manager, Assistant Manager, Nuclear Engineering and Construction, Site Technical Services Manager, as well as Station Technical Manager and Maintenance Engineering Division Manager. Breig has 26 years experience at San Onofre.

Breig began his career with Southern California Edison in 1974, and has held position in Engineering, Construction, Startup, and Project Management at Fossil, Nuclear, and Geothermal Power Plants.

Breig holds a Bachelor of Science degree in Electrical Engineering from the University of Arizona; a Master of Science degree in Electrical Engineering from the University of Southern California (USC); and a Master of Science degree in Mechanical Engineering from California State University at Los Angeles. Breig is also a registered Professional Engineer in the Electrical, Mechanical, and Nuclear disciplines.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company



A. Edward Scherer

Manager, Nuclear Regulatory Affairs
Southern California Edison

As Manager of Nuclear Regulatory Affairs for Southern California Edison, A. Edward Scherer is responsible for managing the interface with the U.S. Nuclear Regulatory Commission, including Plant Licensing, Regulatory Compliance, Decommissioning Licensing, Regulatory Projects (including support for radiation litigation), and Special Regulatory Projects.

Prior to joining SCE in 1998, Scherer was a Vice President at ABB Combustion Engineering. Prior to that, he served in multiple assignments, including project management, reactor engineering, plant start-up, and nuclear licensing. He was appointed Vice President for Nuclear Quality (Nuclear Power) and then served as the Vice President, Regulatory Affairs (Nuclear Fuel) and then Vice President, Business Development (Nuclear Operations).

Scherer earned a Bachelors of Science degree in mechanical engineering from Worcester Polytechnic Institute; a Masters of Science degree in nuclear engineering from the Pennsylvania State University; and a Masters in Business Administration from Rensselaer Polytechnic Institute (Hartford Graduate Center).

Scherer is a Registered Professional Engineer in the Commonwealth of Massachusetts

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

November 14, 2006

R. T. Ridenoure
Vice President
Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FORT CALHOUN STATION - NRC INTEGRATED INSPECTION REPORT 05000285/2006004

Dear Mr. Ridenoure:

On September 30, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Fort Calhoun Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 6, 2006, with Mr. Jeff Reinhart, Site Director, and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents four NRC-identified findings and one self-revealing finding of very low safety significance (Green). All of these findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the violations or significance of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Fort Calhoun Station facility.

In accordance with 10 CFR Part 2.390 of the NRC's "Rules of Practice," a copy of this letter, and its enclosure, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Zachary K. Dunham, Chief
Project Branch E
Division of Reactor Projects

Docket: 50-285
License: DPR-40

Enclosure:
NRC Inspection Report 05000285/2006004
w/Attachment: Supplemental Information

cc w/Enclosure:
Joe I. McManis, Manager - Licensing
Omaha Public Power District
P.O. Box 550
Fort Calhoun, NE 68023-0550

David J. Bannister
Manager - Fort Calhoun Station
Omaha Public Power District
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RIV:RI:DRP/E	SRI:DRP/E	C:DRS/EB1	C:DRS/OB	
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-285
License:	DPR-40
Report:	05000285/2006004
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	Fort Calhoun Station FC-2-4 Adm. P.O. Box 399, Highway 75 - North of Fort Calhoun Fort Calhoun, Nebraska
Dates:	July 1 through September 30, 2006
Inspectors:	J. Hanna, Senior Resident Inspector L. Willoughby, Resident Inspector B. Baca, Health Physicist, Plant Support Branch, Health Physics G. Pick, Senior Reactor Inspector, Engineering, Branch 2 R. Lantz, Senior Emergency Preparedness Inspector J. Adams, Reactor Inspector, Engineering Branch 1 G. George, Reactor Inspector, Engineering Branch 1 S. Graves, Reactor Inspector, Engineering Branch 1 (NSPDP) J. Groom, Reactor Inspector, Engineering Branch 1 (NSPDP) M. Murphy, Senior Operations Engineer S. Garchow, Operations Engineer
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Approved By:	Zachary K. Dunham, Chief, Project Branch E Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 0500285/2006004; 7/1/2006 - 9/30/2006; Fort Calhoun Station; Permanent Plant Modifications, Refueling and Other Outage Activities, Access Control to Radiologically Significant Areas, Other Activities.

The report covered a 3-month period of inspections by resident inspectors and announced inspections by a health physicist, a senior engineering reactor inspector, engineering reactor inspectors, engineering contractors, a senior operations engineer, an operations engineer and a senior emergency preparedness inspector. Five Green findings, all of which were noncited violations, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a Green, noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for failure to use the correct total dead weight of the replacement pressurizer in two design calculations.

  The failure to correctly translate the total dead weight of the replacement pressurizer into design calculations is a performance deficiency because the licensee failed to meet 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and the cause was reasonably within the licensee's ability to foresee and correct. The finding is more than minor because it affects the design control attribute of the initiating events objective listed in Manual Chapter 0612, "Power Reactor Inspection Reports," Appendix B. Because the incorrect weight was used in the analyses, the analyses were re-evaluated. Since the finding did not result in a loss of function or mitigation capability, the violation has very low safety significance (Green), using Manual Chapter 0609, "Significance Determination Process."

  This finding has a crosscutting aspect in the area of human performance because the licensee failed to use conservative assumptions in their decision-making. This caused the licensee to miss opportunities to revise specific design documentation for the pressurizer. A contributing factor is the licensee's regard toward the replacement pressurizer as a "like-for-like" replacement for the original pressurizer. Although the design function of the replacement pressurizer is similar to the original pressurizer, specific design parameters, such as weight, volume, and heater capacity, are actually different (Section 1R17).

Cornerstone: Mitigating Systems

- Green. A noncited violation was identified for failure to comply with Technical Specification 2.1.1.(3), which required two operable decay heat removal loops. This failure resulted in a condition where only one shutdown cooling train was operable. This condition existed for 2 days before being detected by operations personnel.

  This finding was determined to be greater than minor in that it affected the "Configuration Control" attribute of the Mitigating Systems cornerstone. The inspectors evaluated this finding using Manual Chapter 0609, Appendix G, because the condition occurred and was identified during shutdown conditions. Using Checklist 2, the inspectors determined that the finding screened as Green because the condition did not increase the likelihood that a loss of decay heat removal would occur due to failure of the system itself. This condition was entered into the licensee's corrective action program as Condition Report 200603965. This finding has a crosscutting aspect in the area of human performance associated with decision making because operations personnel incorrectly concluded that the shutdown cooling header was operable (Section 1R20).

- Green. The inspectors identified a noncited violation of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, Procedure SO-G-28, "Station Fire Plan," Revision 61, Attachment 14, failed to list operable diagnostic instrumentation, actions needed to respond to faults on 4 kV busses, and had operators re-enter an area without ensuring it was safe to enter.

  This finding is of greater than minor safety significance because it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Consequently, the inspectors evaluated these deficiencies using Manual Chapter 0609, Appendix F. Since the issue involved postfire safe shutdown actions in the auxiliary building related to maintaining reactor coolant system inventory and maintaining a heat sink, had existed for more than 30 days, and had a moderate degradation rating, the issue did not screen out in Phase 1. Because of the room volumes and the forced ventilation flow rates, the sources did not generate sufficient heat in the hot gas layer to damage the targets. Consequently, in accordance with the Appendix F, Step 2.3, of the Phase 2 significance determination process, the inspectors concluded that this finding was of very low safety significance. In addition, this finding had a crosscutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement manual actions existed for postfire safe shutdown (Section 4OA5.3).

- Green. The inspectors identified a noncited violation of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, simulated operator actions during a walkthrough of Procedure AOP-06, "Fire Emergency," could not be performed in the time specified in engineering calculations, nor were all appropriate steps specified.

This finding is of greater than minor safety significance because it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Specifically, the issue involved postfire safe shutdown actions in the auxiliary building upon evacuation from the control room related to maintaining a heat sink. Because of other actions that would likely have been taken, the inspectors concluded this issue had a low degradation rating and, therefore, the inspectors concluded the issue was of very low safety significance in Phase 1. In addition, this finding had a crosscutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement the actions existed (Section 4OA5.4).

Cornerstone: Occupational Radiation Safety

- Green. The inspectors reviewed two examples of a self-revealing, noncited violation of Technical Specification 5.11.1 in which workers failed to obtain high radiation area access authorization and associated radiological briefing before entering the area. The first example occurred on March 26, 2005, when a worker received a dose rate alarm while assisting with the movement of an equipment cutter known to generate a high radiation area. The second example occurred on September 16, 2006, when a worker received two dose rate alarms while working on two fire detectors in the overhead. The worker passed through a high radiation area while performing work on the second fire detector. For the first example, the licensee enhanced pre-job briefings to verify appropriate authorizations and briefings via self and peer checking. For the second example, corrective actions are still being implemented.

  This finding is greater than minor because it is associated with one of the cornerstone attributes (exposure/contamination control) and affects the Occupational Radiation Safety cornerstone objective, in that the failure to obtain high radiation area authorized access and associated radiological briefings resulted in additional personnel exposure. Using the Occupational Radiation Safety Significance Determination Process, the inspectors determined that this finding was of very low safety significance because it did not involve: (1) an ALARA finding, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess doses. Additionally, this finding had a cross-cutting aspect in the area of human performance because the workers failed to use error prevention tools such as self and peer checking. (Section 2OS1)

B. Licensee Identified Findings

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers (condition report numbers) are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The unit began this inspection period in Mode 1 at full rated thermal power and operated at 100 percent until August 18, 2006, when power was decreased on the unit to 97 percent to perform Moderator Temperature Coefficient testing. On August 20, reactor power was increased to 100 percent, where the plant remained until September 9. On September 9 the unit was manually tripped in order to start the refueling outage for replacement of the steam generators, pressurizer and reactor vessel head components. The unit remained shutdown at the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

a. Inspection Scope

The inspectors reviewed the effectiveness of the licensee's implementation of changes to the facility structures, systems, and components; risk-significant normal and emergency operating procedures; test programs; and the updated final safety analysis report in accordance with 10 CFR 50.59, "Changes, Tests, and Experiments." The inspectors utilized Inspection Procedure 71111.02, "Evaluation of Changes, Tests, or Experiments," for this inspection.

The procedure specifies five as the minimum sample size of safety evaluations and a combination of 10 applicability determinations and screenings, with the emphasis on screenings.

The inspectors reviewed five safety evaluations performed by the licensee since the last NRC inspection of this area at Fort Calhoun Station, with an emphasis on replacement nuclear steam supply system components. The evaluations were reviewed to verify that licensee personnel had appropriately considered the conditions under which the licensee may make changes to the facility or procedures or conduct tests or experiments without prior NRC approval. The inspectors reviewed 20 licensee-performed applicability determinations and screenings in which, licensee personnel determined that neither screenings nor evaluations were required to ensure that the exclusion of a full evaluation was consistent with the requirements of 10 CFR 50.59. Procedures, evaluations, screenings, and applicability determinations reviewed are listed in the attachment to this report

The inspectors reviewed and evaluated a sample of recent licensee condition reports to determine whether the licensee had identified problems related to the 10 CFR 50.59 evaluations, entered them into the corrective action program, and resolved technical concerns and regulatory requirements.

The inspection procedure specifies inspectors' review of a required minimum sample of 5 licensee safety evaluations and 10 applicability determinations and screenings (combined). The inspectors completed review of 5 licensee safety evaluations and 20 applicability determinations and screenings (combined).

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Equipment Walkdowns

a. Inspection Scope

The inspectors: (1) walked down portions of the three risk important systems listed below and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walkdown to the licensee's Updated Safety Analysis Report (USAR) and Corrective Action Program to ensure problems were being identified and corrected.

- July 18, 2006, Raw Water to Component Cooling Water Heat Exchangers AC-1B, AC-1C, and AC-1D while AC-1A was out of service for maintenance on relief valve RW-221
- July 25, 2006, Component Cooling Water system that supports Spent Fuel Pool Cooling
- September 22, 2006, Spent Fuel Pool cooling system with the fuel from the core fully offloaded

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors walked down the six plant areas listed below to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the USAR to determine if the licensee identified and corrected fire protection problems.

- July 17, 2006, Gas Decay Tank WD-29C vault, Room 17 (Fire Area 6.1)
- July 25, 2006, Cask Decontamination Area, Room 67 (Fire Area 20.7)
- July 25, 2006, Auxiliary Building 1025 Elevation Work Area, Room 71 (Fire Area 28)
- July 29, 2006, Review of effect of underground fire main break on other portions of the plant
- August 24, 2006, Spent Resin Storage Tank Room (Fire Areas 20.1 and 20.6)
- September 29, 2006, Upper Level of Auxiliary Building, Room 69 (Fire Area 20.7)

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

.1 Semi-annual Internal Flooding

a. Inspection Scope

The inspectors: (1) reviewed the USAR, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the Corrective Action Program to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the areas listed below to verify the adequacy of: (a) equipment seals located below the flood line,

(b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- September 29, 2006, Auxiliary Building 971 Elevation (Rooms 21 and 22)

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspection Activities

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. On August 1, 2006 the inspectors observed training scenarios that involved various equipment failures. The first scenario included a main feed water line rupture while the second scenario included a primary to secondary leak with a station blackout. The inspectors compared performance in the simulator with performance observed in the control room during this inspection period. The focus of the inspection was on high-risk licensed operator actions, operator activities associated with the emergency plan, and previous lessons-learned items. These items were evaluated to ensure that operator performance was consistent with protection of the reactor core during postulated accidents.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Regional Biennial Examination

a. Inspection Scope

This inspection was held during the last week of the biennial examination testing cycle, which ended the week of August 7, 2007. The inspectors reviewed the overall pass/fail results of the individual job performance measure operating tests, simulator operating tests, and written examinations administered by the licensee during the operator licensing requalification cycles and biennial examination. Ten separate crews participated in simulator operating tests, and job performance measure operating tests, totaling 46 licensed operators. While there were a few individual job performance measure failures, all of the licensed operators tested passed the biennial examination.

During the inspection, the inspectors reviewed and observed biennial examination simulator job performance measures, in-plant job performance measures, the simulator static exam, written examination, licensed operator classroom instruction, and the plant control room crew. They also reviewed a sample of licensed operator annual medical forms and procedures governing the medical examination process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the two maintenance activities listed below in order to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule, 10 CFR Part 50 Appendix B, and the Technical Specifications.

- September 25, 2006, Instrument Air Dryer failures
- September 28, 2006, Fuel Oil Tank FO-38 Level Switch LS-2120

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

Risk Assessment and Management of Risk

a. Inspection Scope

The inspectors reviewed the five assessment activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- July 11, 2006, Equipment stored on top of containment

- July 17, 2006, water supply from Blair, Nebraska out of service resulting in Condensate Storage Tank level lowering to less than 67 percent

- September 7, 2006, review of licensee's risk assessment for the Fall 2006 refueling outage and replacement of major components to ensure shutdown risk management objectives were acceptable (e.g. reduced inventory considerations, control of heavy loads, alternate power)

- September 10, 2006, Component Cooling Water Pump AC-3B out of service with the reactor on shut down cooling and 161kV off-side power unavailable

- September 12, 2006, Component Cooling Water Pump AC-3B out of service with the reactor at midloop conditions

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plants status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the USAR and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- July 19, 2006, Diesel Generator 2 Jacket Water Temperature High and Lube Oil Cooler Temperature High alarms while the machine was loaded for monthly surveillance test

- August 30, 2006, YCV-817B Diesel Generator 2 Room Fresh Air Supply Damper lower two damper vanes secured closed by grout

- September 29, 2006, Containment Duct Relief Port open to atmosphere

Documents reviewed by the inspectors included: CR 200603052, CR 200603597, and CR 200604230.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17B)

a. Inspection Scope

The inspection procedure requires inspection of a minimum sample size of five permanent plant modifications.

The inspectors reviewed eight permanent plant modification packages and associated documentation, such as; implementation reviews, safety evaluation applicability determinations, and screenings, to verify that they were performed in accordance with regulatory requirements and plant procedures. The inspectors also reviewed the procedures governing plant modifications to evaluate the effectiveness of the program for implementing modifications to risk-significant systems, structures, and components, such that these changes did not adversely affect the design and licensing basis of the facility. Procedures and permanent plant modifications reviewed are listed in the attachment to this report. Further, the inspectors interviewed certain of the cognizant design and system engineers for the identified modifications as to their understanding of the modification packages and process.

The inspectors evaluated the effectiveness of the licensee's corrective action process to identify and correct problems concerning the performance of permanent plant modifications by reviewing a sample of related condition reports. The reviewed condition reports are identified in the attachment.

The inspection procedure specifies inspectors' review of a required minimum sample of five permanent plant modifications. The inspectors completed review of eight permanent plant modifications.

b. Findings

Failure to Translate Replacement Pressurizer Weight Into Design Calculations

Introduction. The inspectors identified a Green, NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for failure to use the correct total dead weight of the replacement pressurizer in two design calculations. In addition, this finding has a human performance crosscutting aspect.

Description. On August 8, 2006, the inspectors reviewed Engineering Change EC 32447, "Pressurizer Replacement." Engineering Change EC 32447, Section 4.3.3, states design loads of the replacement pressurizer for the structural analysis will be a total dead weight consisting of the replacement pressurizer filled with cold water including insulation. This weight is about 191 kips. The inspectors identified that in two calculations, FC 03122, "10-inch Surge Line Break," and FC 07085, "Pressurizer Anchor Bolts", Fort Calhoun Station personnel used a replacement pressurizer weight that is substantially lower than the pressurizer total dead weight, as stated in Engineering Change EC 32447. Calculation FC 03122, the referenced loading analysis for the slab carrying the replacement pressurizer, used a total weight of 181 kips. Calculation FC07085, the referenced seismic analysis for the pressurizer anchoring, used a total weight of 144 kips.

After discussion with licensee personnel, the analyses were reevaluated using more conservative weight assumptions. The issue was entered into the corrective action program as CR 200603413.

Analysis. The failure to correctly translate the total dead weight of the replacement pressurizer into design calculations is a performance deficiency because the licensee failed to meet 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and the cause was reasonably within the licensee's ability to foresee and correct. The finding is more than minor because it affects the design control attribute of the initiating events cornerstone objectives listed in Manual Chapter 0612, "Power Reactor Inspection Reports," Appendix B. Because the incorrect weight was used in the analyses, the analyses were re-evaluated. Since the finding did not result in a loss of function or mitigation capability, the violation has very low safety significance (Green), using Phase 1 of Manual Chapter 0609, "Significance Determination Process."

This finding has a crosscutting aspect in the area of human performance because the licensee failed to use conservative assumptions in their decision-making. This caused the licensee to miss opportunities to revise specific design documentation for the pressurizer. A contributing factor is the licensee's regard towards the replacement pressurizer as a "like-for-like" replacement for the original pressurizer. Although the design function of the replacement pressurizer is similar to the original pressurizer, specific design parameters, such as weight, volume, and heater capacity, are actually different.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, states, in part, measures shall be established to assure that applicable regulatory requirements and the design basis, for structures, systems, and components, are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to this, as of August 8, 2006, Fort Calhoun Station personnel had failed to correctly translate the replacement pressurizer total dead weight into two analysis: (1) seismic design of pressurizer anchor bolts; and (2) integrity of the slab and compartment supporting the pressurizer.

Because this failure to comply with 10 CFR Part 50, Appendix B, Criterion III, is of very low safety significance and has been entered into the licensee's corrective action program as CR 200603413, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000285/2006004-01 Failure to Translate Replacement Pressurizer Weight Into Design Calculations.)

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the five postmaintenance test activities listed below of risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the USAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- September 6, 2006, Replace Filter or Regulator Assembly for IA-HCV-2883B-FR (Work Order 00217639-01)
- September 6, 2006, In-office review of post maintenance test on Charging Pump CH-1A following performance of SP-CP-08-480-1B3A, "Calibration of Protective Relays for 480-1B3A Bus," Revision 14
- September 6, 2006, Replace Steam Generator RC-2A Blow-down to Blow-down Tank FW-7 Control Valve HCV-1390 (Work Order 00218435-01)
- September 6, 2006, repair the Fire Main Rupture between FP-106 and FP-104 (Work Order 00244394-01)
- September 6, 2006, in-office review of postmaintenance test on High Pressure Safety Injection Pump SI-2C following performance of SP-CP-08-480-1B3A, "Calibration of Protective Relays for 480-1B3A Bus," Revision 14

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the following risk significant refueling items or outage activities to verify defense in depth commensurate with the outage risk control plan, compliance with the Technical Specifications, and adherence to commitments in response to

Generic Letter 88-17, "Loss of Decay Heat Removal": (1) the risk control plan; (2) tagging/clearance activities; (3) reactor coolant system instrumentation; (4) electrical power; (5) decay heat removal; (6) spent fuel pool cooling; (7) inventory control; (8) reactivity control; (9) containment closure; (10) reduced inventory or midloop conditions; (11) refueling activities; (12) cooldown activities; and (13) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities. Due to the licensee's refueling outage continuing past the end of the inspection period, activities such as heatup and restart were not yet inspected. The inspectors' reviews particularly focused on establishment of plant conditions necessary for the replacement of the major components (i.e., steam generators, pressurizer, reactor vessel head). Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

Introduction. The inspectors identified a Green NCV for failure to comply with Technical Specification 2.1.1.(3), which required two operable decay heat removal loops. This failure resulted in a condition where only one shutdown cooling train was operable. This condition existed for 2 days before being detected by operations personnel.

Description. On September 9, 2006, the licensee commenced shutdown of the plant in support of the Fall 2006 refueling outage. On September 10, at approximately 9:30 a.m., operations personnel performed the initial valve lineup per OI-SC-1, "Shutdown Cooling Initiation," Revision 42, for establishment of shutdown cooling. (This procedure established the configuration of systems necessary to further lower plant temperature and maintain core cooling.) At 12:30 p.m., reactor coolant temperature decreased to less than 210°F and pressure was lowered below the necessary minimum for single reactor coolant pump operation. Once this condition existed, Technical Specification 2.1.1.(3) became applicable and the steam generators became unavailable as a heat removal source due to inability to run reactor coolant pumps to dissipate decay heat.

On September 12, at approximately 7:30 p.m., a valve lineup was subsequently performed for the purpose of re-verifying the configuration of the system. Operators performing this valve lineup discovered that manual isolation Valve SI-173 (Shutdown Heat Exchanger AC-4A & 4B Outlet Cross Connect Valve) was locked shut. The valve was immediately restored to the open position. The licensee determined that, on September 9, 2006, when Procedure OI-SC-1 had last been performed, a procedure requirement to open Valve SI-173 had been inadvertently signed as completed without the valve actually being repositioned.

The inspectors determined that, had a failure of the operating Train A of shutdown cooling occurred, Train B would not have been available. Significant diagnosis would have been required during a postulated event in order to determine the cause of lack of flow. Further, licensee Procedure AOP-19, "Loss of Shutdown Cooling," Revision 12, which the operators would use to respond to such an event, did not require them to either verify or reposition Valve SI-173. The initial determination by operations personnel (i.e., that Train B of shutdown cooling had been operable while in the isolated condition) was questioned by the inspectors. Fort Calhoun Station's operability determination of the shutdown cooling train was later revised to reflect that it had in fact been inoperable.

Analysis. The inspectors determined that the failure to comply with Technical Specifications for the reactor coolant system was a performance deficiency. This finding was determined to be greater than minor in that it affected the "Configuration Control" attribute of the Mitigating Systems cornerstone. The inspectors evaluated this finding using Manual Chapter 0609, Appendix G, because the condition occurred and was identified during shutdown conditions. Using Checklist 2 the inspectors determined that the finding screened as Green because the condition did not increase the likelihood that a loss of decay heat removal would occur due to failure of the system itself. This finding has a crosscutting aspect in the area of human performance associated with decision making because operations personnel incorrectly concluded that the shutdown cooling header was operable.

Enforcement. Technical Specification 2.1.1.(3) requires, in part, that with "T_{cold} less than 210°F with fuel in the reactor and all reactor vessel head closure bolts fully tightened, at least two of the decay heat removal loops . . . shall be operable." Operable is defined in the Technical Specifications as "when it is capable of performing its specified function(s)." Contrary to the above, on September 10-12, 2006, only one train of shutdown cooling was operable. This violation of Technical Specification 2.1.1.(3) is being treated as a noncited violation, consistent with Section VI.A of the Enforcement Policy (NCV 05000285/2006004-02). This violation was entered into the licensee corrective action program as CR 200603965.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the USAR, procedure requirements, and Technical Specifications to ensure that the five surveillance activities listed below demonstrated that the SSCs tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms set points. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- July 27, 2006, observed the Independent Spent Fuel Storage Facility surveillance test MSLT-DSC-TriVis, "Helium Mass Spectrometer Leak Test Procedure" Revision FtC-0

- August 16, 2006, Surveillance Test IC-ST-MS-0031, “Channel Calibration of Steam Generator RC-2B Channel B Pressure Loop B/P-905,” Revision 14

- August 18, 2006, review of the leak detection activities conducted in accordance with OP-ST-RC-3001, “Reactor Coolant System Leak Rate Test,” during a period of slightly elevated leakage

- August 23, 2006, Surveillance Test IC-ST-RPS–0055, “Calibration of Power Range Safety Channel C,” Revision 2

- August 29, 2006, In service Test SE-ST-MS-3005, “Main Steam Safety Valves Set pressure Using Trevitest Equipment,” Revision 4

Documents reviewed by the inspectors are shown above.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors performed in-office reviews of revisions to the Fort Calhoun Station Emergency Plan, including Revision 13 to Section D, Revision 33 to Section H, and Revision 19 to Section J. The inspectors also reviewed Revisions 40 and 41 to Emergency Plan Implementing Procedure OSC-1, "Emergency Classification." The revisions were submitted between April and August, 2006. The revisions (1) added procedural direction for implementation of the requirements of 10 CFR Part 72 for a dry fuel storage program, (2) added new emergency action level (7.1) for damage to a loaded dry fuel cask confinement boundary, (3) revised protective action recommendation guidance to specify the criteria for a sheltering recommendation in lieu of an evacuation recommendation during short term (< 1 hour) radiological releases with limited dose projections, and (4) relocated one emergency alert siren a minor distance with the concurrence of the Department of Homeland Security.

The revisions were compared to their previous revisions, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, to the criteria of NEI 99-01, "Methodology for Development of Emergency Action Levels," Revision 2, and to the standards in 10 CFR 50.47(b) to determine if the revisions were adequately conducted following the requirements of 10 CFR 50.54(q). This review was not documented in a Safety Evaluation Report and did not constitute approval of licensee changes, therefore, these revisions are subject to future inspection.

The inspectors completed one sample during the inspection.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas (HRAs), and worker adherence to these controls. The inspectors used the requirements in 10 CFR Part 20, the Technical Specifications, and the licensee's procedures required by Technical Specifications as criteria for determining compliance. During the inspection, the inspectors interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspectors performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone

- Controls (surveys, posting, and barricades) of radiation, high radiation, and potential airborne radioactivity areas in the Reactor, Spent Fuel, and Auxiliary Buildings

- Radiation work permits, procedures, engineering controls, and air sampler locations

- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms.

- Barrier integrity and performance of engineering controls in two potential airborne radioactivity areas

- Adequacy of the licensee's internal dose assessment for any actual internal exposure greater than 50 millirem Committed Effective Dose Equivalent

- Physical and programmatic controls for highly activated or contaminated materials (non-fuel) stored within the spent fuel pool.

- Self-assessments, audits, licensee event reports, and special reports related to the access control program since the last inspection

- Corrective action documents related to access controls

- Radiation work permit briefings and worker instructions

- Adequacy of radiological controls such as, required surveys, radiation protection job coverage, and contamination controls during job performance

- Dosimetry placement in high radiation work areas with significant dose rate gradients

- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas

- Controls for special areas that have the potential to become very high radiation areas during certain plant operations

- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

- Radiation worker and radiation protection technician performance with respect to radiation protection work requirements

The inspectors completed 20 of the required 21 samples.

b. Findings

Introduction. The inspectors reviewed two examples of a self-revealing, noncited violation of Technical Specification 5.11.1, in which workers failed to obtain a high radiation area access authorization and associated radiological briefing before entering into the area. The violation had very low safety significance.

Description. The first example occurred on March 26, 2005, when a worker received a dose rate alarm while participating in the movement of equipment cutters with radiation readings greater than 100 millirem per hour at 30 centimeters. An investigation into the dose rate alarm revealed the individual was briefed and authorized for work activities, which did not include entries into high radiation areas. The individual voluntarily assisted another work group with the cutter movement but did not consider the limitations of his prior briefing and the high radiation area access authorization. In addition, the radiation protection technician covering the work activity assumed all individuals in the work area were appropriately briefed and authorized for the work activity. The licensee enhanced pre-job briefings to include additional radiation protection staff and worker self and peer checking to verify appropriate authorizations and briefings were performed.

The second example occurred on September 16, 2006, when a worker received two dose rate alarms while working on two fire detectors in the overhead between the equipment hatch and the pressurizer cubicle. The work scope was discussed with radiation protection personnel at the containment control point but was not sufficiently communicated with the radiation protection technician providing the pre-job surveys. This led the radiation protection technician to only survey and evaluate the fire detector that was in an open area and not the second area. After completing work on the fire detector in the open area, the worker used the nearby cable trays to gain access to the second fire detector where he passed in close proximity to the safety injection line. The worker received two dose rate alarms (going to and returning from) the second fire detector. The worker then exited containment and reported the alarms to radiation protection. The worker's dose rate alarm was set at 40 millirem per hour, the peak dose rate seen by the electronic alarming dosimeter was 102 millirem per hour, and a survey of the safety injection line after the event identified 110 millirem per hour at 30 cm. The worker failed to obtain radiological conditions and access authorization for the second area entered.

Analysis. The failure to obtain high radiation area access authorization and associated radiological briefings before entering the area is a performance deficiency. This finding is greater than minor because it is associated with one of the cornerstone attributes (exposure/contamination control) and affects the Occupational Radiation Safety cornerstone objective, in that the failure to obtain high radiation area authorized access and associated radiological briefings resulted in additional personnel exposure. Using the Occupational Radiation Safety Significance Determination Process, the inspectors determined that this finding was of very low safety significance because it did not involve: (1) an ALARA finding, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess doses. Additionally, this finding had a crosscutting aspect in the area of human performance because the workers failed to use error prevention tools such as self and peer checking.

Enforcement. Technical Specification 5.11.1 states, in part, that in lieu of the "control device" required by 10 CFR 20.1601(a) and 20.1601(c), each high radiation area, as defined in 10 CFR 20.1601, shall be barricaded and conspicuously posted as a high radiation area and entrance thereto controlled by a Radiation Work Permit. Any individuals permitted to enter such areas shall be provided with a continuously integrating and alarming radiation-monitoring device and may enter after the dose rate levels in the area have been established and personnel are made knowledgeable of them. Contrary to Technical Specifications, workers entered high radiation areas without obtaining the required radiological briefing and were not specifically authorized to enter the areas. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program (Condition Reports CR 200501675 and CR 200604123), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000285/2006004-03, Failure to obtain high radiation area access authorization and associated radiological briefing.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20 and the licensee's procedures required by Technical Specifications as criteria for determining compliance. The inspectors interviewed licensee personnel and reviewed:

- Three outage work activities scheduled during the inspection period and associated work activity exposure estimates which were likely to result in the highest personnel collective exposures

- Interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups

- Integration of ALARA requirements into work procedure and radiation work permit (or radiation exposure permit) documents

- Exposure tracking system

- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding

- Workers use of the low dose waiting areas

- First-line job supervisors' contribution to ensuring work activities are conducted in a dose efficient manner

- Specific sources identified by the licensee for exposure reduction actions and priorities established for these actions, and results achieved against since the last refueling cycle

- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

- Self-assessments, audits, and special reports related to the ALARA program since the last inspection

- Corrective action documents related to the ALARA program and follow-up activities such as initial problem identification, characterization, and tracking

The inspectors completed 4 of the required 15 samples and 7 of the optional samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Occupational Radiation Safety Cornerstone

- Occupational Exposure Control Effectiveness

The inspectors reviewed licensee documents from January 1, 2005, through June 30, 2006. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in the licensee's technical specifications), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in NEI 99-02). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data. In addition, the inspectors toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 3, were used to verify the basis in reporting for each data element.

The inspectors completed the required sample (1) in this cornerstone.

Public Radiation Safety Cornerstone

- Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

The inspectors reviewed licensee documents from January 1, 2005, through June 30, 2006. Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded PI thresholds and those reported to the NRC. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data. PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 3, were used to verify the basis in reporting for each data element.

The inspectors completed the required sample (1) in this cornerstone.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Fire Protection Unresolved Item Review

a. Inspection Scope

As part of the unresolved item closeout inspection, the inspectors assessed: (1) the corrective actions implemented for each specific unresolved item, (2) the self assessment performed to evaluate the fire protection program progress and readiness for this inspection, (3) plans implemented related to manual actions for 10 CFR Part 50, Appendix R, Section III.G.2 areas.

The inspectors conducted this inspection through documentation review and interviews with engineering and licensing personnel.

b. Observations and Findings

The inspectors noted that the licensee had taken significant steps to identify the extent of condition related to the unresolved items identified in the August 2005 triennial fire protection inspection. However, the inspectors noted that the licensee had not completed their procedure revisions at the time of this inspection. Similarly, the licensee had not finalized the engineering review of the engineered safety feature actuations.

The self assessment performed in June 2006 provided critical recommendations of the fire protection organization's progress related to the unresolved items and the level of detail in the plan to resolve the large number of manual actions for Appendix R, Section III.G.2 areas that did not have exemptions in place. For example, the self-assessment noted that the plans for resolving the use of manual actions, as documented in CR 200601090 did not have sufficient detail to drive the issue to resolution.

.2 Problem Identification and Resolution for Radiation Protection

a. Inspection Scope

The inspectors evaluated the effectiveness of the licensee's problem identification and resolution process with respect to the following inspection areas:

- Access Control to Radiologically Significant Areas (Section 2OS1)
- ALARA Planning and Controls (Section 2OS2)

b. Findings

No findings of significance were identified.

.3 Routine Review of Identification and Resolution of Problems with a Operator Work Around

a. Inspection Scope

The inspectors chose one issue (one inspection sample) for more in-depth review to verify that the licensee personnel had taken corrective actions commensurate with the significance of the issue. The inspectors reviewed the corrective actions associated with this condition including the licensee's classification of the issue being an operator work around. The inspectors also performed a review of operator workarounds, control room deficiencies, and control room burden lists. The inspectors focused on the cumulative effects of the workaround on the reliability/availability of mitigating systems and the corresponding impact on operators to respond in a correct and timely manner to plant transients and accidents. The inspectors reviewed the deficiencies against the licensee's Procedure OPD-4-17, "Control Room Deficiencies, Operator Burdens, and Operator Workaround," Revision 16, that described the programs for handling workarounds and deficiencies. The following issue was evaluated:

- Review of CR 2005005837 Degraded FI-417, Flow Indicator for Cooling Water Flow from VA-1B

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000285/2005008-01: Failure to maintain the safety injection and refueling water tank valves free of fire damage

Introduction. The inspectors determined that the failure to have the cable separation required by 10 CFR Part 50, Appendix R, Section III.G.2, to the suction valves located between the safety injection and refueling water tank and the safety injection pumps would not have resulted in closure of the valves. The short that could result would not generate sufficient voltage to actuate the solenoid for the suction valves. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

Description. During the triennial fire protection inspection in August 2005, the team determined that a fire in Fire Area 20 could potentially cause loss of redundant trains of systems and equipment credited in the postfire safe shutdown analysis. Specifically, the safe shutdown analysis credited the use of Safety Injection Pumps SI-2A or SI-2B taking suction from the safety injection and refueling water tank.

The team had determined that: (1) the postfire safe shutdown analysis credited Valves LCV-383-1 and LCV-383-2 for the safety injection system to accomplish its shutdown function and at least one of the two valves must remain free of fire damage; (2) a single hot short on Cable EB3884 (Valve LCV-383-1) or Cable EA3890 (Valve LCV-383-2) could cause the associated valve to fail in the undesired (closed) position; and (3) the licensee had routed both cables in cable trays that are located less that 10 feet apart horizontally. The licensee initiated CR 200504001 to place this item into their corrective action program and had established an hourly fire watch for this fire area as an interim compensatory measure.

During this inspection, the inspectors: (1) reviewed Operability Evaluation for Valves LCV-383-1 and LCV-383-2, (2) verified that the indicating lamp had a 2000-ohm resistor, (3) verified that the solenoid had a maximum resistance of 885 ohms, and (4) verified the solenoid required 90 Vdc to actuate. The worst-case scenario resulted from a short from the close circuit to the solenoid actuation circuit that placed the indicating lamp and solenoid in series in the 125 Vdc circuit. Analyzing the circuit determined that the solenoid would draw 38.4 Vdc, which would not actuate the solenoid and inadvertently close the valves.

Analysis. Routing the cables for safety-related valves needed for postfire safe shutdown within 10 feet of each other was a performance deficiency for failure to meet the separation requirements specified in 10 CFR Part 50, Appendix R, Section III.G.2. This finding was determined to be of minor safety significance because it would not have impacted the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Specifically, a fire in Fire Area 20 did not have the potential to cause damage to circuits that could adversely affect the ability of the licensee to provide makeup to the reactor coolant system via the safety injection and refueling water tank.

Enforcement. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered this deficiency into their corrective action program as CR 200504001. The inspectors determined that the licensee had initiated Project Number FC 38203 in April 2006 to route one of the cables in a conduit or relocate to another fire area because of the continued noncompliance with 10 CFR Part 50, Appendix R, Section III.G.2.

.2 (Closed) Unresolved Item 05000285/2005008-02: Lack of an evaluation of fire-induced automatic actuation signals on a fire area basis

Introduction. The inspectors determined that the failure to evaluate fire-induced actuations of engineered safety feature actuation system sensors and cables as required by 10 CFR Part 50, Appendix R, Section III.G.2 would not have resulted in actuation of components needed for hot shutdown. The evaluation that was performed did identify circuits subject to spurious actuation needed for cold shutdown, which could be repaired within the 72 hours allowed. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

Description. During the triennial fire protection inspection in August 2005, the team determined that the safe shutdown analysis had not evaluated engineered safety feature actuation system automatic control systems or related instrumentation and cables that could have a significant impact on safety if damaged during a fire. For example, for Fire Area 20 the safe shutdown analysis credits the use of safety injection pumps taking suction from the safety injection and refueling water tank. However, if a recirculation actuation signal occurred because of fire damage, the discharge valves for the tank would close and the suction for the pumps could be transferred to a dry containment sump, which could damage the pumps. The licensee entered this finding into the corrective action program as CR 200503738 and established an hourly fire watch for this fire area as an interim compensatory measure.

During this inspection, the inspectors reviewed Calculation EA 06-008, "Engineered Safety Features Actuation System (ESFAS) Fire-Induced Failure Evaluation," Revision 0, and discussed the results with the fire protection engineer. Calculation EA 06-008 evaluated the circuits related to the re-circulation actuation signal, the containment spray actuation signal, the safety injection actuation signal, the containment isolation actuation signal, and the steam generator isolation signal. The inspectors determined that the evaluation appropriately identified each sensor and sensor cable for faults. The evaluation identified that many circuits needed for cold shutdown would require manual actions to resolve spurious operation and made corrective action recommendations. Some conclusions did not clearly indicate that the spurious operation would not affect achieving hot shutdown.

Consequently, the inspectors interviewed the fire protection engineer and reviewed Calculation EA-FC-89-055, "10 CFR Part 50, Appendix R, Safe Shutdown Analyses," Revision 12. This review confirmed that components affected were not required for a long period, were needed to achieve cold shutdown, and were being addressed in the update to Procedure AOP-06, "Fire Emergency," Revision 16. Consequently, the inspectors concluded that the potential circuit failures would have little effect on the ability of the licensee staff to achieve hot shutdown.

Analysis. The failure to evaluate engineered safety feature actuation systems for fire-induced circuit failures resulted in a performance deficiency for failure to meet the separation requirements specified in 10 CFR Part 50, Appendix R, Section III.G.2. This finding was determined to be of minor safety significance because it would not have impacted the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Specifically, the failure to evaluate fire-induced actuations, including the impact on safe shutdown, of the engineered safety feature actuation systems instrumentation and cables did not affect response activities to achieve hot shutdown.

Enforcement. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered this deficiency into their corrective action program as CR 200503738. At the time of this inspection, the licensee had recently received the evaluation from their contractor and had not completed all of their engineering reviews.

.3 (Closed) Unresolved Item 05000285/2005008-03: Inadequate procedure for implementing the fire protection program as required by Technical Specification 5.8.1.c.

Introduction. The inspectors identified a Green NCV of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, Procedure SO-G-28, "Station Fire Plan," Revision 61, did not provide adequate instructions for operators to mitigate the effects of fire damage.

Description. During the triennial fire protection inspection in August 2005, the team identified several deficiencies related to the postfire safe shutdown procedures. Operators used Procedure AOP-06, "Fire Emergency," Revision 11 to implement the detailed response when evacuating the control room, including manual actions. Procedure SO-G-28 provided instructions for operators to mitigate the effects of fire damage to safe shutdown equipment in plant areas other than the control room and the cable spreading room. Procedure SO-G-28, Attachment 14, "Restoration of Safe Shutdown Conditions in the Event of a Fire," described the fire areas that required the use of manual operator actions to mitigate fires in those areas for fires other than a control room evacuation.

As a result of tabletop walkthroughs and simulator evaluations using Procedures AOP-06 and SO-G-28, the team had determined that Procedure SO-G-28: (1) was not referred to in Procedure AOP-06; (2) did not direct operators to enter Attachment 14 nor did operators refer to the attachment; (3) did not identify the diagnostic instrumentation that may be relied upon for a fire in each fire area; (4) main body did not provide operators detailed information identifying the manual actions to be performed in response to a fire; (5) did not provide operators information as to which, if any, manual actions are time critical; and (6) for Fire Area 43, required operators to re-enter the area if a fire had occurred to close Manual Valve IA-3119. In summary, the team concluded that manual actions were not reliable and feasible because of the lack of diagnostic instruments being identified, the poor coordination among the various procedures, and operator's lack of familiarity with Procedure SO-G-28, Attachment 14, which identified key manual actions needed.

During this inspection, the inspectors identified postfire safe shutdown components in Fire Areas 20, 32 and 43 which required manipulation to safely shutdown the reactor for fires outside the control room. For Fire Area 20 (Room 69), the inspectors concluded that Procedure SO-G-28 provided appropriate guidance through redirection to AOP-32, "Loss of 4160 Volt or 480 Volt Bus Power," Revision 10, and EOP-20,"Functional Recovery Procedure," Revision 18. The third action in this fire area involved valving in raw water to the control room HVAC upon loss of normal cooling water. The inspectors considered this action low risk since the control room heat-up would be gradual. However, the inspectors noted that, at the time of this finding, the procedure remained deficient in that it had not identified the instruments that remained operable.

For Fire Area 32 (Room 19), Procedure SO-G-28, Attachment 14 failed to list operable diagnostic instrumentation and actions needed to respond to spurious operation of components powered from the 4 kV busses. Similarly, for Fire Area 43 (Room 81), Procedure SO-G-28, Attachment 14, failed to identify operable diagnostic instruments and required operators to re-enter the room when it may not have been habitable. The inspectors determined that the references to other emergency and abnormal operating procedures provided appropriate implementing instructions.

The licensee had entered these deficiencies into their corrective action program as CRs 200503731, 200504006, and 200504203. The inspectors verified that the licensee had revised Procedure SO-G-28 to refer to Attachment 14 and to include the operable diagnostic information in Attachment 14. In addition, the licensee had initiated revisions to Procedure AOP-06 to incorporate the guidelines contained in Procedure SO-G-28 and provided more detailed mitigation steps. Upon final approval all guidance would be contained in Procedure AOP-06. This finding had a cross-cutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement manual actions for postfire safe shutdown.

Analysis. The failure of Procedure SO-G-28 to provide adequate instructions to operators to perform manual actions to mitigate the consequences of fire damage and ensure hot shutdown could be achieved was a performance deficiency for failure to meet Technical Specification 5.8.1.c. Specifically, Procedure SO-G-28, Attachment 14, failed to list operable diagnostic instrumentation, actions needed to respond to faults on 4 kV busses, and had operators re-enter an area without knowing it would be safe. This deficiency was more than minor in that it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Consequently, the inspectors evaluated these deficiencies using Manual Chapter 0609, Appendix F

The actions for Fire Area 32 (Room 19) were postfire safe shutdown functions in the auxiliary building related to maintaining reactor coolant system inventory (inadvertent operation of the power-operated relief valves), had existed for more than 30 days, and had a moderate degradation rating. Consequently, the issue did not screen out in Phase 1. During the Phase 2 evaluation, the inspectors identified the ignition sources (air compressor motor, air compressor oil, turbine-driven auxiliary feedwater pump oil, electrical control cabinet for the air compressor, motor driven auxiliary feedwater pump motor) and the targets (thermoset cable). One component, compressor electrical cabinets, did not screen out and required use of the NUREG-1805 model for a room with forced ventilation to determine the hot gas layer temperature. Because of the room volume and the forced ventilation flow rate, the electrical cabinet did not generate sufficient heat in the hot gas layer to damage the thermoset cables.

The actions for Fire Area 43 (Room 81) were postfire safe shutdown functions in the auxiliary building related to maintaining a heat sink (operability of auxiliary feedwater), had existed for more than 30 days, and had a moderate degradation rating. Consequently, the issue did not screen out in Phase 1. During the Phase 2 evaluation, the inspectors identified the ignition sources (ventilation unit motors and wood staged in a metal gang box) and the targets as the E/P converter for the auxiliary feedwater air-operated valves and the electric panels for the main steam code safeties. One component, electric cables to the E/P converter for the air-operated auxiliary feedwater valve, did not screen out and required use of the NUREG-1805 model for a room with forced ventilation to determine the hot gas layer temperature. Because of the room volume and the forced ventilation flow rate, the wood in the metal gang box (assumed the wood was not enclosed) did not generate sufficient heat in the hot gas layer to damage the cables to the E/P converter.

However, because the potential for fire damage did not exist in Fire Areas 32 and 43 as determined by the Appendix F, Step 2.3 Phase 2 significance determination process for each fire area, the inspectors concluded that this finding was of very low safety significance (Green).

Enforcement. Technical Specification 5.8.1.c. requires that written procedures and administrative policies shall be established, implemented and maintained covering fire protection program implementation. Procedure SO-G-28 provided the guidance to operators, including manual actions, to achieve postfire safe shutdown. Inspection Procedure 71111.05T, Enclosure 2, specified the criteria that must be met for manual actions to be considered feasible without an approved exemption to 10 CFR Part 50, Appendix R. Contrary to the above, the inspectors determined that Procedure SO-G-28 failed to meet the following manual action feasibility criteria: (1) procedure guidance failed to identify exactly what manual actions were needed, (2) diagnostic instruments that remained operable for a fire in each fire area were not identified, and (3) directed operators to the area without any guidelines for when it would be safe to manipulate a component in the same area. Because this finding is of very low safety significance and has been entered into the corrective action program (CR 200504203), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000285/2006004-04, Failure to implement reasonable and feasible manual actions.

.4 (Closed) Unresolved Item 05000285/2005008-04: Inadequate fire safe shutdown procedure for control room evacuation

Introduction. The inspectors identified a Green NCV of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, simulated operator actions during a walkthrough of Procedure AOP-06, "Fire Emergency," Revision 12, could not be performed in the time specified in engineering calculations nor were all appropriate steps specified.

Description. During the triennial fire protection inspection in August 2005, the team identified, during timed walkthroughs of AOP-06, Section II, "Control Room Evacuation," that the procedure had inadequate guidance. The team determined that Procedure AOP-06, Section II: (1) identified establishing control for alternate shutdown at AI-179, Auxiliary Feedwater Panel, and AI-185, Alternate Shutdown Panel, (2) failed to identify a time frame for establishing auxiliary feedwater whereas calculations specified time frames as short as 12 minutes, and (3) prior to establishing control at Panel AI-179, required the communicator to manually throttle Valves HCV-1107B, "Steam Generator RC-2A Auxiliary Feedwater Inlet Valve," and HCV-1108B, "Steam Generator RC-2B Auxiliary Feedwater Inlet Valve," to 75 percent closed.

Further, the team determined that: (1) the communicator can easily meet the time line in the calculations with the valves in their normally closed position. However, if the valves receive a spurious open signal prior to throttling, interviews with operators indicated that the valves may not be able to be manually throttled, and (2) Procedure AOP-06, Section II, identified no contingency actions to throttle the valves closed or for establishing control at Panel AI-179 if the valves were not throttled closed.

During this inspection, the inspectors verified the licensee had corrected the deficiencies identified by the team. Further, the licensee entered this finding into the corrective action program as CR 200503731 and revised Procedure AOP-06 to include contingency actions should the valves open prior to completion of manual throttling. This finding had a crosscutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement the actions.

Analysis. The failure of Procedure AOP-06 to provide sufficient guidance was a performance deficiency for failure to meet Technical Specification 5.8.1.c. Specifically, the procedure failed to ensure that response personnel had the appropriate guidance and equipment to allow them to carry out the functions of limiting auxiliary feedwater flow to the steam generators when needed. This deficiency was more than minor in that it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Consequently, the inspectors evaluated these deficiencies using Manual Chapter 0609, Appendix F.

Because of other actions that would, likely, have been taken, the inspectors concluded this issue had a low degradation rating and, therefore, the inspector concluded the issue had very low safety significance in the Phase 1 evaluation.

Enforcement. Technical Specification 5.8.1.c. requires that written procedures and administrative policies shall be established, implemented and maintained covering fire protection program implementation. Procedure AOP-06, Section II, provided the guidance to operators, including manual actions, to achieve postfire safe shutdown for a control room evacuation. Inspection Procedure 71111.05T, Enclosure 2, specified the criteria that must be met for manual actions to be considered feasible without an approved exemption to 10 CFR Part 50, Appendix R. Contrary to the above, the inspectors determined that Procedure AOP-06, Section II, failed to ensure that manual operation of auxiliary feedwater valves would be accomplished prior to the times specified in engineering calculations and failed to ensure sufficient guidance and tools existed for equipment operators to accomplish the task. Specifically, the procedure specified no time limit, and the communicator, during timing evolutions, indicated that if the valves were open the 12-minute time limit would not be met and he had no way of informing the control room supervisor because he did not carry a radio. Because this finding is of very low safety significance and has been entered into the corrective action program (CR 200503731), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000285/2006004-05, Inadequate alternate shutdown procedure.

.5 (Closed) LER 05000285/2006002-00, Inadequate Design Control Results in Potentially Insufficient Auxiliary Feedwater Flow

The details of this condition are discussed in Section 4OA7 of this report. This LER is closed.

4OA6 Meetings

Exit Meeting Summary

The inspectors discussed the preliminary results of the fire protection unresolved item review with Mr. J. Reinhart, Site Director, and other members of licensee management on July 21, 2006. The inspectors returned proprietary information examined during the inspection to the licensee. The inspectors conducted a telephonic exit meeting with Mr. Joe McManis, Manager, Nuclear Licensing, and other licensee personnel on August 18, 2006. Licensee management acknowledged the inspection results.

On August 10, 2006, the operator licensing inspectors conducted a debrief meeting to present the licensed operator requalification inspection results to the Licensee's management team. During the debrief, the inspectors informed the management team they had obtained permission to retain copies of six medical certification forms containing privacy information act material. It had also been agreed this material would be shredded upon issuance of the inspection report. The licensee was informed that a final exit for the inspection would be conducted after the requalification program was completed and the NRC had reviewed the final results. On September 20, 2006, a final exit, which described the inspection results, was conducted by the inspectors via telephone with Mr. D. Weaver, Supervisor of Operations Training. The licensee acknowledged the findings presented in both the briefing and the final exit meeting. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On August 11, 2006, the inspectors presented the safety evaluation and permanent plant modifications inspection results to Mr. J. Reinhert, Site Director, and other members of the staff who acknowledged the findings. While some proprietary information was reviewed during this inspection, no proprietary information was included in this report.

On August 30, 2006, the inspectors presented the results of the emergency plan change inspection to Mr. C. Simmons, Supervisor, Emergency Preparedness. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On September 22, 2006, the inspectors presented the occupational radiation safety inspection results to Mr. J. Reinhart, Site Director, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

The results of the resident inspector activities were presented to Mr. J. Reinhart, Site director, and other members of licensee management on October 6, 2006. The inspectors confirmed that proprietary information examined during the inspection period was returned to the licensee. Licensee management acknowledged the inspection findings.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- Title 10 CFR Part 50, Appendix B, Section III, "Design Control," states, in part, that "Measures shall also be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety related functions of the SSCs." Contrary to the above, the electrical power supply to flow transmitter FT-1368 (Motor Driven Auxiliary Feedwater Pump Suction Flow Transmitter) was not safety-related. During an event the flow transmitter and associated recirculation valve may not perform its design function consequently challenging the ability of the Motor Driven Auxiliary Feedwater Pump to provide cooling to the steam generators. This finding only had very low safety significance because it was a design or qualification deficiency confirmed not to result in loss of operability. This finding was identified in the licensee's corrective action program as CR 200602855 and was reported as LER 05000285/2006-002-00.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Bannister, Plant Manager
B. Blessie, Supervisor, Operations Engineer
D. Buell, Fire Protection Engineer
T. Byrne, Licensing Engineer (Title 10 CFR 50.59 Program Coordinator)
G. Cavanaugh, Supervisor, Regulatory Compliance
S. Cofaul, ALARA Technician, Radiation protection
M. Core, Manager, System Engineering
H. Faulhaber, Division Manager, Engineering
M. Ferm, Manager, Shift Operations
W. Goddell, Nuclear Training Manager
D. Guinn, Licensing Engineer
W. Hansher, Lead, Nuclear Safety Review
R. Haug, manager, Radiation Protection
K. Hyde, Supervisor, mechanical Engineering
R. Jaworski, Licensing Engineer
G. Labs, Simulator Supervisor
D. Lakin, Manager, Corrective Action Program
T. Maine, Supervisor, Radiation Protection
E. Matzke, Compliance Engineer
J. McManis, Manager, Licensing
T. Nellenbach, Manager, Operations
M. Pohl, Principal Reactor Engineer, Operations
M. Quinn, Nuclear Engineering and Computing Projects Supervisor
J. Reinhart, Site Director
R. Short, Manager, NSSS Replacement Components
C. Simmons, Supervisor, Emergency Preparedness
M. Tesar, Division manager, Nuclear Support Services
J. Tills, Manager, Maintenance
D. Travsch, Manager, Quality
D. Weaver, Operations and Technical Training Supervisor
J. Willett, Principle Reactor Engineer Fuels, Operations
C. Williams, Supervisor, Radiation Protection

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Open and Closed

05000258/2006004-01	NCV	Failure to Translate Replacement Pressurizer Weight Into Design Calculations (Section 1R17)
05000285/2006004-02	NCV	Failure to Maintain Shutdown Cooling Train Operable as Required by Technical Specification 2.1.1.(3) (Section 1R20)

05000285/2006004-03	NCV	Failure to Obtain High Radiation Area Access Authorization and an Associated Radiological Briefing (Section 2OS1)
05000285/2006004-04	NCV	Failure to Implement Reasonable and Feasible Manual Actions (Section 4OA5.3)
05000285/2006004-05	NCV	Inadequate Alternate Shutdown Procedure (Section 4OA5.4)

Closed

05000285/2005008-01	URI	Failure to Maintain the Safety Injection and Refueling Water Tank Valves Free of Fire Damage (Section 4OA5.1)
05000285/2005008-02	URI	Lack of an Evaluation of Fire-Induced Automatic Actuation Signals on a Fire Area Basis (Section 4OA5.2)
05000285/2005008-03	URI	Inadequate Procedure for Implementing the Fire Protection Program as Required by Technical Specification 5.8.1.c. (Section 4OA5.3)
05000285/2005008-04	URI	Inadequate Fire Safe Shutdown Procedure for Control Room Evacuation (Section 4OA5.4)
05000285/2006002-00	LER	Inadequate Design Control Results in Potentially Insufficient Auxiliary Feedwater Flow (Section 4OA7)

LIST OF DOCUMENTS REVIEWED

Section 1R02: Evaluations of Changes, Tests, or Experiments

10 CFR 50.59 Evaluations

FC-071145, LTR-RCPL-04-75, OPPD Replacement Pressurizer
EC 33109
EC 38303
FC-154B for EC-31589
FC-154B for EC-38331

10 CFR 50.59 Screenings

EC 33116
FC-154A, EC-33105
EC 33117
EC 33109
EC-154A for EC-31589 (RSG)
FC-154A for EC-31589 (RSG Type C-6 Nozzle Dams)
FC-154A for EC-33106
EC 33153
EC 25764 for USAR Section 14 Revision
EC 33104

Applicability Determinations

FC-68C for EC 33105
EC 33116
EC 33117
EC 33109
EC 33115
FC-68C for EC 31589
FC-68C for EC 33106
EC 33153
EC 25764 for USAR Section 14 Revision
EC 33104

Procedures

NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews"

Section 1RO4: Equipment Alignment

Licensee Procedure OI-SFP-1, "Spent Fuel Pool Cooling Normal Operations," Revision 29

Licensee Procedure ARP-CB-1,2,3/A1, "Annunciator Response Procedure A1 Control Room Annunciator A1", Revision 26

Drawing 11405-M11, "Auxiliary Coolant Spent Fuel Pool Cooling System Flow Diagram P&ID," Revision 52

Section 1RO5: Fire Protection

Standing Order SO-G-28, "Station Fire Plan," Revision 66

Standing Order SO-G-102, "Fire Protection Program," Revision 7

Abnormal Operating Procedure AOP-6, "Fire Emergency," Revision 17

USAR, Section 9.11, "Fire Protection Systems"

Section 1RO6: Flood Protection Measures

Probabilistic Risk Assessment Summary Notebook, Revision 4

Individual Plant Examination Submittal, dated December 1993

Section 1R11: Licensed Operator Requalification Program

Open Simulator Discrepancy Reports (All)
Closed Simulator Discrepancy Reports Summary from January 2006 thru May 2006
Simulator Configuration Review Group (SCRG) meeting minutes for 2005
Simulator Annual Performance Test book for 2006

Simulator Steady State Testing Packages for 100% and 30% Power
Simulator Transient Testing Packages for Tests Three, Eight, and Ten
Current Simulator Differences List
Core physics testing packages for simulator, Cycle 23.
Low Power Physics Test data from the plant, Cycle 23.
Simulator Modification Procedures
Verification and Validation Procedures
Operator licensing tracking system active operator licenses (R4 OLTS report)
Current operator license list from Fort Calhoun Station
AP 21-001, Conduct of Operations, Rev. 35
AI 21-100, Operations Guidance and Expectations, Rev. 6
AI 30B-005, Conduct of Simulator Activities for Licensed Operator Training, Rev.8A
AP 30B-001, Licensed Operator Requalification Training Program, Rev. 7A
AP 30B-006, Shift Engineer/Shift Technical Advisor Requalification Training Program, Rev. 3
DTI 204, Operator Requalification JPM Preparation, Validation, and Administration

Section 1R12: Maintenance Effectiveness

Condition Reports

200503725	200505469	200600189	200601570
200603628			

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

Standing Order SO-O-21, "Shutdown Operations Protection Plan," Revision 25

Condition Report 200602982

Control Room Operating Logs, dated July 16 and July 17, 2006

Risk evaluation and risk management actions per e-mail from John Fluehr, OPPD dated July 18, 2006

Section 1R17B: Permanent Plant Modifications

Plant Modifications

Number	Title	Revision
EC 32447	Replacement Pressurizer	0
EC 33105	Pressurizer Replacement	0
EC 33106	Steam Generator Large Bore Piping	0
EC 33116	Pressurizer Heater Cable Replacement	0
EC 33109	Containment Opening	0
EC 31589	Fort Calhoun - Replacement Steam Generators (Component)	0

EC 33153	Fort Calhoun - Replacement Reactor Vessel Head (Component)	0
EC 33104	Steam Generator Replacement	0

Engineering Changes

Number	Title	Revision
EC 38331	Safety Injection Phase Performance for Safety Injection and Containment Spray Systems Calculation No. FC07077	0
EC 33115	Temporary Transformer/RC-3A Tie-In	0
EC 33117	Replacement Pressurizer Instrument Modification	0
EC 38303	Recirculation Phase System Performance for Safety Injection and Containment Spray Systems	0

Drawings

ISO WD-2072, Sh.1	File 8939	9
ISO CH-2049, Sh. 1	File 8187	9
04-30991-01	Y-Globe Valve, Socket Ends...Size 2, Class 1878	0
11405-S-39	Reactor Plant Ground Floor Plan El. 1013'-0" Reinf. Sh.1	5

Calculations

FC 03122	10" Surge Line Break Effect on Pressurizer Slab and Walls below Pressurizer Compartment	1
FC 07085	Pressurizer Anchor Bolts	0
FC07172 (Bechtel Calculation 25036-C-029)	Evaluation of Containment Structure for Construction Opening	0
Combustion Engineering Calculation 0-SEC-15	Determination of Pressurizer Heater Capacity	7/12/67
FC 06974 (Areva Calculation) 32-5046461-00	FCS RSG – Decay Heat Removal Cap. In Nat. Circ. Analysis	4/1/04
32-5046526-00	FCS RSG – Loss of Load to Both Steam Generators Analysis	10/22/04

FC 07186	Fort Calhoun Scaling Calculation for Replacement Pressurizer Level Transmitters	3
CN-RVHP-05-59	Fort Calhoun Head Lift NUREG-0612 Evaluation	1
WB-CN-ENG-05-32	Fort Calhoun - Cap Screw Design	1
FC 03231	FCS RCS Support Validation	0

Procedures

Number	Title	Revision
SO-G-21	Standing Order Modification Control	78
PED-GEI-3	Preparation of Modification	42
PED-QP-2	Configuration Change Control	29
PSC Procedure F&Q 15.0	Precision Surveillance Corporation Field and Quality Control Procedure for Tendon Re-stressing	1
PSC Procedure F&Q 15.2	Precision Surveillance Corporation Field and Quality Control Procedure for Bearing Plate Concrete Inspection	0

Miscellaneous Documents

Number	Title	Revision
NPM-210	Nuclear Procurement Manual	13
N/A	Licensing Amendment Request Status Log	15
SA-06-23	Self Assessment Report, 10CFR50.50 Implementation	7/27/06
N/A	Watlow Pressurizer Heater Accelerated Life Test Status Report	7/12/06
FCSG-23	10 CFR 50.59 Resource Manual	5
FC-07145, LTR-RCPL-05-115	Final Design Licensing Report for the OPPD Replacement Pressurizer	0
FCP-KBS-05-00014	Accelerated Life Test Procedure for Heaters of RPZR	1
FCP-KBS-06-0002	RPZR Heater Accelerated Life Test Results for Short Term Electrical Failures	0
LIC-05-0107	Fort Calhoun Station Unit No. 1 License Amendment Request, "Updated Safety Analysis Report Revision for Radiological Consequences Analysis for Replacement NSSS Components"	10/31/05

NUREG 0800	Standard Review Plan for the Review of Safety Reports for Nuclear Power Plants	2
AREVA Engineering Information Record	FCS RSG - Control System Evaluation, 51-5050728-01	1
EA-FC -02-028	Appendix K Power Uprate Evaluation, Section 5	0
Email from Alan Wang (NRC) to Leonard M. Willoughby (NRC)	AST Accident Dose - Criteria for Categorical Exclusion	8/10/06
LTR-RCPL-05-135	Final Design Licensing Report for the OPPD Replacement Reactor Vessel Head and Rapid Refueling Package (RRVH/RRP)	0
RFP 1758	Technical Specification for Design of Mirror Insulation for the Replacement Reactor Vessel Head for Omaha Public Power District, Fort Calhoun Station	0
MR FC-79-15	Replacement of Reactor Pressure Vessel and Seismic Skirt Insulation; Appendix 7.2, Section H, Contract 1318 Technical Specification	4/82

Condition Reports

CR 200603413	CR 200402963	CR 200504555	CR 200600896
CR 200600624	CR 00602152	CR 200601839	CR 200603179
CR 200504214	CR 200600395	CR 200603252	CR 200504503
CR 200402637	CR 200504503	CR 200500408	CR 200600750
CR 200602255	CR 200403490	CR 200601815	CR 200505022
CR 200600454	CR 200602693	CR 200603374	CR 200401985
CR 200503149	CR 00600195	CR 200501970	

Section 1R19: Postmaintenance Testing

Work Order 00217639-01, Replace Filter or Regulator Assembly for IA-HCV-2883B-FR

Procedure SP-CP-08-480-1B3A, "Calibration of Protective Relays for 480-1B3A Bus," Revision 14

Work Order 00218435-01, Replace Steam Generator RC-2A Blow-down to Blow-down Tank FW-7 Control Valve HCV-1390

Work Order 00244394-01, Repair the Fire Main Rupture between FP-106 and FP-104

Section 1R20: Refueling and Other Outage Activities

Shutdown Safety Advisor's Log dated September 13, 2006

Technical Specifications, Definitions Section, page 5

OI-SC-1, "Shutdown Cooling System," Revision 42

Drawing D-4768, "Primary Plant Simplified Flowpath Diagram," Revision 5

Abnormal Operating Procedure AOP-19, "Loss of Shutdown Cooling," Revision 12

Root Cause Analysis Report for CR 200603965

Section 2OS1: Access Controls to Radiologically Significant Areas (71121.01)

Audits, Self-Assessments, and Surveillances

Quality Assurance Audit Report No. 49/58
Self-Assessment SA-06-02
Surveillance Report 58(3)-0506

Condition Reports

200500993, 200501625, 200501675, 200600870, 200601277, 20061866, 200603848, 200604123

Procedures

RP-202	Radiation Protection Radiological Surveys, Revision 26
RP-204	Radiological Area Controls, Revision 44
RP-208	Radiography, Revision 10
RP-602	Radiation Protection Personnel Dosimetry Issuance and Change-out, Revision 20
RP-608	Dose Calculations from Contamination, Revision 11
RPI-13	Radiological Posting Standards, Revision 2
SO-G-92	Conduct of Infrequently Performed Procedures, Revision 9
SO-G-101	Radiation Worker Practices, Revision 30
SO-O-47	Spent Fuel Pool Inventory Control, Revision 6

Radiation Work Permits

06-3001, 06-3520, 06-3533, and 06-3541

Sample Results and Surveys

Air Sample Form and Results for RWP 06-3541 on 09/21/06
Survey Numbers: 05-1173, 06-1088

Miscellaneous

2005 DAC-Hour Tracking Summary
Dose Rate Alarm Report
Shift Outage Manager's Reports

Section 2OS2: ALARA Planning and Controls (71121.02)

Audits, Self-Assessments, and Surveillances

Quality Assurance Audit Report No. 49/58
Self-Assessment SA-06-02
Surveillance Report 58(3)-0506

Condition Reports

200504826, 200505725, 200602354

Radiation Work Permits

06-3520, 06-3533, and 06-3541

Procedures

RP-301 ALARA Planning / RWP Development and Control, Revision 26

Miscellaneous

Shift Outage Manager's Reports

Section 4OA1: Performance Indicator Verification (71151)

Procedures

NOD-QP-40 NRC Performance Indicator Program, Revision 2

Miscellaneous

2005 Abnormal Batch Liquid and Gaseous Release Summary
2005 Batch Liquid and Gaseous Release Summary
2005 Liquid Effluents Continuous Mode
Surveillance Report Numbers: 63(3)-0606 and 63(3)-1105

Section 4OA5: Other Activities (71111.05T)

Procedures

AOP-06, "Fire Emergency," Revisions 15 and 16
AOP-32, "Loss of 4160 Volt or 480 Volt Bus Power," Revision 10
EOP-06, "Loss of All Feedwater," Revision 12
EOP-20, "Functional Recovery Procedure," Revision 18
FCSG, "Performing Risk Assessments,"
OPD-2-06, "Operations Department Duties and Responsibilities," Revision 21
SO-G-28, "Station Fire Plan," Revisions 61 and 65
SO-—100, "Conduct of Maintenance," Revision 41
SO-O-1, "Conduct of Operations," Revision 69

Drawings

11405-—253, “Flow Diagram, Steam Generator Feedwater and Blowdown,” Sheet 4, Revision 3

11405-S-64, “Auxiliary Building Sections,” Sheet 2, Revision 4

Calculations

EA 06-008, “Engineered Safety Features Actuation System (ESFAS) Fire-Induced Failure Evaluation,” Revision 0

EA-FC-89-055, “10 CFR Part 50, Appendix R, Safe Shutdown Analysis,” Revisions 11 and 12

EA-FC-97-001, “Fire Hazards Analysis (FHA) Manual,” Revision 11

EA-FC-97-044, “10 CFR Part 50, Appendix R, Cable Identification,” Revision 4

FC 05814, “UFHA Combustible Loading,” Revision 9

Condition Reports

200204316	200503731	200503738	200503750	200503979	200504001
200504006	200504203	200601090			

Miscellaneous

Engineering Information Record 51-9016709-00, “Fort Calhoun Station Transient Analysis, Manual Action Timeline and Feasibility Study,” dated June 21, 2006

Fisher-Rosemount Vendor Manual, “Type 657 Diaphragm Actuator, Sizes 30 - 70 and 87"

LIST OF ACRONYMS

CFR *Code of Federal Regulations*
CR Condition Report
NCV noncited violation
NRC Nuclear Regulatory Commission
SSC Structure, System and Component
USAR Updated Safety Analysis Report

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

November 14, 2006

R. T. Ridenoure
Vice President
Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FORT CALHOUN STATION - NRC INTEGRATED INSPECTION REPORT 05000285/2006004

Dear Mr. Ridenoure:

On September 30, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Fort Calhoun Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 6, 2006, with Mr. Jeff Reinhart, Site Director, and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents four NRC-identified findings and one self-revealing finding of very low safety significance (Green). All of these findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the violations or significance of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Fort Calhoun Station facility.

In accordance with 10 CFR Part 2.390 of the NRC's "Rules of Practice," a copy of this letter, and its enclosure, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Zachary K. Dunham, Chief
Project Branch E
Division of Reactor Projects

Docket: 50-285
License: DPR-40

Enclosure:
NRC Inspection Report 05000285/2006004
w/Attachment: Supplemental Information

cc w/Enclosure:
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Electronic distribution by RIV:
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Senior Project Engineer, DRP/E **(DLL1)**
Team Leader, DRP/TSS **(RVA)**
RITS Coordinator **(KEG)**
DRS STA **(DAP)**
J. Lamb, OEDO RIV Coordinator **(JGL1)**
ROPreports
FCS Site Secretary **(BMM)**
W. A. Maier, RSLO **(WAM)**
R. E. Kahler, NSIR **(REK)**

SUNSI Review Completed: ______ ADAMS: √ Yes ☐ No Initials: zkd
√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

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RIV:RI:DRP/E	SRI:DRP/E	C:DRS/EB1	C:DRS/OB	
LMWilloughby	JDHanna	JAClark	RLNease	
T-ZKDunham	***T-ZKDunham***	***/RA/***	***/RA/***	
11/ /06	11/ /06	11/9/06	11/8/06	
C:DRS/EB2	STA:DRS	C:DRP/E		
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-285
License:	DPR-40
Report:	05000285/2006004
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	Fort Calhoun Station FC-2-4 Adm. P.O. Box 399, Highway 75 - North of Fort Calhoun Fort Calhoun, Nebraska
Dates:	July 1 through September 30, 2006
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TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 0500285/2006004; 7/1/2006 - 9/30/2006; Fort Calhoun Station; Permanent Plant Modifications, Refueling and Other Outage Activities, Access Control to Radiologically Significant Areas, Other Activities.

The report covered a 3-month period of inspections by resident inspectors and announced inspections by a health physicist, a senior engineering reactor inspector, engineering reactor inspectors, engineering contractors, a senior operations engineer, an operations engineer and a senior emergency preparedness inspector. Five Green findings, all of which were noncited violations, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a Green, noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for failure to use the correct total dead weight of the replacement pressurizer in two design calculations.

  The failure to correctly translate the total dead weight of the replacement pressurizer into design calculations is a performance deficiency because the licensee failed to meet 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and the cause was reasonably within the licensee's ability to foresee and correct. The finding is more than minor because it affects the design control attribute of the initiating events objective listed in Manual Chapter 0612, "Power Reactor Inspection Reports," Appendix B. Because the incorrect weight was used in the analyses, the analyses were re-evaluated. Since the finding did not result in a loss of function or mitigation capability, the violation has very low safety significance (Green), using Manual Chapter 0609, "Significance Determination Process."

  This finding has a crosscutting aspect in the area of human performance because the licensee failed to use conservative assumptions in their decision-making. This caused the licensee to miss opportunities to revise specific design documentation for the pressurizer. A contributing factor is the licensee's regard toward the replacement pressurizer as a "like-for-like" replacement for the original pressurizer. Although the design function of the replacement pressurizer is similar to the original pressurizer, specific design parameters, such as weight, volume, and heater capacity, are actually different (Section 1R17).

Cornerstone: Mitigating Systems

- Green. A noncited violation was identified for failure to comply with Technical Specification 2.1.1.(3), which required two operable decay heat removal loops. This failure resulted in a condition where only one shutdown cooling train was operable. This condition existed for 2 days before being detected by operations personnel.

  This finding was determined to be greater than minor in that it affected the "Configuration Control" attribute of the Mitigating Systems cornerstone. The inspectors evaluated this finding using Manual Chapter 0609, Appendix G, because the condition occurred and was identified during shutdown conditions. Using Checklist 2, the inspectors determined that the finding screened as Green because the condition did not increase the likelihood that a loss of decay heat removal would occur due to failure of the system itself. This condition was entered into the licensee's corrective action program as Condition Report 200603965. This finding has a crosscutting aspect in the area of human performance associated with decision making because operations personnel incorrectly concluded that the shutdown cooling header was operable (Section 1R20).

- Green. The inspectors identified a noncited violation of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, Procedure SO-G-28, "Station Fire Plan," Revision 61, Attachment 14, failed to list operable diagnostic instrumentation, actions needed to respond to faults on 4 kV busses, and had operators re-enter an area without ensuring it was safe to enter.

  This finding is of greater than minor safety significance because it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Consequently, the inspectors evaluated these deficiencies using Manual Chapter 0609, Appendix F. Since the issue involved postfire safe shutdown actions in the auxiliary building related to maintaining reactor coolant system inventory and maintaining a heat sink, had existed for more than 30 days, and had a moderate degradation rating, the issue did not screen out in Phase 1. Because of the room volumes and the forced ventilation flow rates, the sources did not generate sufficient heat in the hot gas layer to damage the targets. Consequently, in accordance with the Appendix F, Step 2.3, of the Phase 2 significance determination process, the inspectors concluded that this finding was of very low safety significance. In addition, this finding had a crosscutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement manual actions existed for postfire safe shutdown (Section 4OA5.3).

- Green. The inspectors identified a noncited violation of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, simulated operator actions during a walkthrough of Procedure AOP-06, "Fire Emergency," could not be performed in the time specified in engineering calculations, nor were all appropriate steps specified.

This finding is of greater than minor safety significance because it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Specifically, the issue involved postfire safe shutdown actions in the auxiliary building upon evacuation from the control room related to maintaining a heat sink. Because of other actions that would likely have been taken, the inspectors concluded this issue had a low degradation rating and, therefore, the inspectors concluded the issue was of very low safety significance in Phase 1. In addition, this finding had a crosscutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement the actions existed (Section 4OA5.4).

Cornerstone: Occupational Radiation Safety

- Green. The inspectors reviewed two examples of a self-revealing, noncited violation of Technical Specification 5.11.1 in which workers failed to obtain high radiation area access authorization and associated radiological briefing before entering the area. The first example occurred on March 26, 2005, when a worker received a dose rate alarm while assisting with the movement of an equipment cutter known to generate a high radiation area. The second example occurred on September 16, 2006, when a worker received two dose rate alarms while working on two fire detectors in the overhead. The worker passed through a high radiation area while performing work on the second fire detector. For the first example, the licensee enhanced pre-job briefings to verify appropriate authorizations and briefings via self and peer checking. For the second example, corrective actions are still being implemented.

  This finding is greater than minor because it is associated with one of the cornerstone attributes (exposure/contamination control) and affects the Occupational Radiation Safety cornerstone objective, in that the failure to obtain high radiation area authorized access and associated radiological briefings resulted in additional personnel exposure. Using the Occupational Radiation Safety Significance Determination Process, the inspectors determined that this finding was of very low safety significance because it did not involve: (1) an ALARA finding, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess doses. Additionally, this finding had a cross-cutting aspect in the area of human performance because the workers failed to use error prevention tools such as self and peer checking. (Section 2OS1)

B. Licensee Identified Findings

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers (condition report numbers) are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The unit began this inspection period in Mode 1 at full rated thermal power and operated at 100 percent until August 18, 2006, when power was decreased on the unit to 97 percent to perform Moderator Temperature Coefficient testing. On August 20, reactor power was increased to 100 percent, where the plant remained until September 9. On September 9 the unit was manually tripped in order to start the refueling outage for replacement of the steam generators, pressurizer and reactor vessel head components. The unit remained shutdown at the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

a. Inspection Scope

The inspectors reviewed the effectiveness of the licensee's implementation of changes to the facility structures, systems, and components; risk-significant normal and emergency operating procedures; test programs; and the updated final safety analysis report in accordance with 10 CFR 50.59, "Changes, Tests, and Experiments." The inspectors utilized Inspection Procedure 71111.02, "Evaluation of Changes, Tests, or Experiments," for this inspection.

The procedure specifies five as the minimum sample size of safety evaluations and a combination of 10 applicability determinations and screenings, with the emphasis on screenings.

The inspectors reviewed five safety evaluations performed by the licensee since the last NRC inspection of this area at Fort Calhoun Station, with an emphasis on replacement nuclear steam supply system components. The evaluations were reviewed to verify that licensee personnel had appropriately considered the conditions under which the licensee may make changes to the facility or procedures or conduct tests or experiments without prior NRC approval. The inspectors reviewed 20 licensee-performed applicability determinations and screenings in which, licensee personnel determined that neither screenings nor evaluations were required to ensure that the exclusion of a full evaluation was consistent with the requirements of 10 CFR 50.59. Procedures, evaluations, screenings, and applicability determinations reviewed are listed in the attachment to this report

The inspectors reviewed and evaluated a sample of recent licensee condition reports to determine whether the licensee had identified problems related to the 10 CFR 50.59 evaluations, entered them into the corrective action program, and resolved technical concerns and regulatory requirements.

The inspection procedure specifies inspectors' review of a required minimum sample of 5 licensee safety evaluations and 10 applicability determinations and screenings (combined). The inspectors completed review of 5 licensee safety evaluations and 20 applicability determinations and screenings (combined).

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Equipment Walkdowns

a. Inspection Scope

The inspectors: (1) walked down portions of the three risk important systems listed below and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walkdown to the licensee's Updated Safety Analysis Report (USAR) and Corrective Action Program to ensure problems were being identified and corrected.

- July 18, 2006, Raw Water to Component Cooling Water Heat Exchangers AC-1B, AC-1C, and AC-1D while AC-1A was out of service for maintenance on relief valve RW-221
- July 25, 2006, Component Cooling Water system that supports Spent Fuel Pool Cooling
- September 22, 2006, Spent Fuel Pool cooling system with the fuel from the core fully offloaded

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors walked down the six plant areas listed below to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the USAR to determine if the licensee identified and corrected fire protection problems.

- July 17, 2006, Gas Decay Tank WD-29C vault, Room 17 (Fire Area 6.1)
- July 25, 2006, Cask Decontamination Area, Room 67 (Fire Area 20.7)
- July 25, 2006, Auxiliary Building 1025 Elevation Work Area, Room 71 (Fire Area 28)
- July 29, 2006, Review of effect of underground fire main break on other portions of the plant
- August 24, 2006, Spent Resin Storage Tank Room (Fire Areas 20.1 and 20.6)
- September 29, 2006, Upper Level of Auxiliary Building, Room 69 (Fire Area 20.7)

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

.1 Semi-annual Internal Flooding

a. Inspection Scope

The inspectors: (1) reviewed the USAR, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the Corrective Action Program to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the areas listed below to verify the adequacy of: (a) equipment seals located below the flood line,

(b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- September 29, 2006, Auxiliary Building 971 Elevation (Rooms 21 and 22)

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspection Activities

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. On August 1, 2006 the inspectors observed training scenarios that involved various equipment failures. The first scenario included a main feed water line rupture while the second scenario included a primary to secondary leak with a station blackout. The inspectors compared performance in the simulator with performance observed in the control room during this inspection period. The focus of the inspection was on high-risk licensed operator actions, operator activities associated with the emergency plan, and previous lessons-learned items. These items were evaluated to ensure that operator performance was consistent with protection of the reactor core during postulated accidents.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Regional Biennial Examination

a. Inspection Scope

This inspection was held during the last week of the biennial examination testing cycle, which ended the week of August 7, 2007. The inspectors reviewed the overall pass/fail results of the individual job performance measure operating tests, simulator operating tests, and written examinations administered by the licensee during the operator licensing requalification cycles and biennial examination. Ten separate crews participated in simulator operating tests, and job performance measure operating tests, totaling 46 licensed operators. While there were a few individual job performance measure failures, all of the licensed operators tested passed the biennial examination.

During the inspection, the inspectors reviewed and observed biennial examination simulator job performance measures, in-plant job performance measures, the simulator static exam, written examination, licensed operator classroom instruction, and the plant control room crew. They also reviewed a sample of licensed operator annual medical forms and procedures governing the medical examination process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the two maintenance activities listed below in order to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule, 10 CFR Part 50 Appendix B, and the Technical Specifications.

- September 25, 2006, Instrument Air Dryer failures
- September 28, 2006, Fuel Oil Tank FO-38 Level Switch LS-2120

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

Risk Assessment and Management of Risk

a. Inspection Scope

The inspectors reviewed the five assessment activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- July 11, 2006, Equipment stored on top of containment

- July 17, 2006, water supply from Blair, Nebraska out of service resulting in Condensate Storage Tank level lowering to less than 67 percent

- September 7, 2006, review of licensee's risk assessment for the Fall 2006 refueling outage and replacement of major components to ensure shutdown risk management objectives were acceptable (e.g. reduced inventory considerations, control of heavy loads, alternate power)

- September 10, 2006, Component Cooling Water Pump AC-3B out of service with the reactor on shut down cooling and 161kV off-side power unavailable

- September 12, 2006, Component Cooling Water Pump AC-3B out of service with the reactor at midloop conditions

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plants status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the USAR and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- July 19, 2006, Diesel Generator 2 Jacket Water Temperature High and Lube Oil Cooler Temperature High alarms while the machine was loaded for monthly surveillance test

- August 30, 2006, YCV-817B Diesel Generator 2 Room Fresh Air Supply Damper lower two damper vanes secured closed by grout

- September 29, 2006, Containment Duct Relief Port open to atmosphere

Documents reviewed by the inspectors included: CR 200603052, CR 200603597, and CR 200604230.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17B)

a. Inspection Scope

The inspection procedure requires inspection of a minimum sample size of five permanent plant modifications.

The inspectors reviewed eight permanent plant modification packages and associated documentation, such as; implementation reviews, safety evaluation applicability determinations, and screenings, to verify that they were performed in accordance with regulatory requirements and plant procedures. The inspectors also reviewed the procedures governing plant modifications to evaluate the effectiveness of the program for implementing modifications to risk-significant systems, structures, and components, such that these changes did not adversely affect the design and licensing basis of the facility. Procedures and permanent plant modifications reviewed are listed in the attachment to this report. Further, the inspectors interviewed certain of the cognizant design and system engineers for the identified modifications as to their understanding of the modification packages and process.

The inspectors evaluated the effectiveness of the licensee's corrective action process to identify and correct problems concerning the performance of permanent plant modifications by reviewing a sample of related condition reports. The reviewed condition reports are identified in the attachment.

The inspection procedure specifies inspectors' review of a required minimum sample of five permanent plant modifications. The inspectors completed review of eight permanent plant modifications.

b. Findings

Failure to Translate Replacement Pressurizer Weight Into Design Calculations

Introduction. The inspectors identified a Green, NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for failure to use the correct total dead weight of the replacement pressurizer in two design calculations. In addition, this finding has a human performance crosscutting aspect.

Description. On August 8, 2006, the inspectors reviewed Engineering Change EC 32447, "Pressurizer Replacement." Engineering Change EC 32447, Section 4.3.3, states design loads of the replacement pressurizer for the structural analysis will be a total dead weight consisting of the replacement pressurizer filled with cold water including insulation. This weight is about 191 kips. The inspectors identified that in two calculations, FC 03122, "10-inch Surge Line Break," and FC 07085, "Pressurizer Anchor Bolts", Fort Calhoun Station personnel used a replacement pressurizer weight that is substantially lower than the pressurizer total dead weight, as stated in Engineering Change EC 32447. Calculation FC 03122, the referenced loading analysis for the slab carrying the replacement pressurizer, used a total weight of 181 kips. Calculation FC07085, the referenced seismic analysis for the pressurizer anchoring, used a total weight of 144 kips.

After discussion with licensee personnel, the analyses were reevaluated using more conservative weight assumptions. The issue was entered into the corrective action program as CR 200603413.

Analysis. The failure to correctly translate the total dead weight of the replacement pressurizer into design calculations is a performance deficiency because the licensee failed to meet 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and the cause was reasonably within the licensee's ability to foresee and correct. The finding is more than minor because it affects the design control attribute of the initiating events cornerstone objectives listed in Manual Chapter 0612, "Power Reactor Inspection Reports," Appendix B. Because the incorrect weight was used in the analyses, the analyses were re-evaluated. Since the finding did not result in a loss of function or mitigation capability, the violation has very low safety significance (Green), using Phase 1 of Manual Chapter 0609, "Significance Determination Process."

This finding has a crosscutting aspect in the area of human performance because the licensee failed to use conservative assumptions in their decision-making. This caused the licensee to miss opportunities to revise specific design documentation for the pressurizer. A contributing factor is the licensee's regard towards the replacement pressurizer as a "like-for-like" replacement for the original pressurizer. Although the design function of the replacement pressurizer is similar to the original pressurizer, specific design parameters, such as weight, volume, and heater capacity, are actually different.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, states, in part, measures shall be established to assure that applicable regulatory requirements and the design basis, for structures, systems, and components, are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to this, as of August 8, 2006, Fort Calhoun Station personnel had failed to correctly translate the replacement pressurizer total dead weight into two analysis: (1) seismic design of pressurizer anchor bolts; and (2) integrity of the slab and compartment supporting the pressurizer.

Because this failure to comply with 10 CFR Part 50, Appendix B, Criterion III, is of very low safety significance and has been entered into the licensee's corrective action program as CR 200603413, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000285/2006004-01 Failure to Translate Replacement Pressurizer Weight Into Design Calculations.)

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the five postmaintenance test activities listed below of risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the USAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- September 6, 2006, Replace Filter or Regulator Assembly for IA-HCV-2883B-FR (Work Order 00217639-01)

- September 6, 2006, In-office review of post maintenance test on Charging Pump CH-1A following performance of SP-CP-08-480-1B3A, "Calibration of Protective Relays for 480-1B3A Bus," Revision 14

- September 6, 2006, Replace Steam Generator RC-2A Blow-down to Blow-down Tank FW-7 Control Valve HCV-1390 (Work Order 00218435-01)

- September 6, 2006, repair the Fire Main Rupture between FP-106 and FP-104 (Work Order 00244394-01)

- September 6, 2006, in-office review of postmaintenance test on High Pressure Safety Injection Pump SI-2C following performance of SP-CP-08-480-1B3A, "Calibration of Protective Relays for 480-1B3A Bus," Revision 14

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the following risk significant refueling items or outage activities to verify defense in depth commensurate with the outage risk control plan, compliance with the Technical Specifications, and adherence to commitments in response to

Generic Letter 88-17, "Loss of Decay Heat Removal": (1) the risk control plan; (2) tagging/clearance activities; (3) reactor coolant system instrumentation; (4) electrical power; (5) decay heat removal; (6) spent fuel pool cooling; (7) inventory control; (8) reactivity control; (9) containment closure; (10) reduced inventory or midloop conditions; (11) refueling activities; (12) cooldown activities; and (13) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities. Due to the licensee's refueling outage continuing past the end of the inspection period, activities such as heatup and restart were not yet inspected. The inspectors' reviews particularly focused on establishment of plant conditions necessary for the replacement of the major components (i.e., steam generators, pressurizer, reactor vessel head). Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

Introduction. The inspectors identified a Green NCV for failure to comply with Technical Specification 2.1.1.(3), which required two operable decay heat removal loops. This failure resulted in a condition where only one shutdown cooling train was operable. This condition existed for 2 days before being detected by operations personnel.

Description. On September 9, 2006, the licensee commenced shutdown of the plant in support of the Fall 2006 refueling outage. On September 10, at approximately 9:30 a.m., operations personnel performed the initial valve lineup per OI-SC-1, "Shutdown Cooling Initiation," Revision 42, for establishment of shutdown cooling. (This procedure established the configuration of systems necessary to further lower plant temperature and maintain core cooling.) At 12:30 p.m., reactor coolant temperature decreased to less than 210°F and pressure was lowered below the necessary minimum for single reactor coolant pump operation. Once this condition existed, Technical Specification 2.1.1.(3) became applicable and the steam generators became unavailable as a heat removal source due to inability to run reactor coolant pumps to dissipate decay heat.

On September 12, at approximately 7:30 p.m., a valve lineup was subsequently performed for the purpose of re-verifying the configuration of the system. Operators performing this valve lineup discovered that manual isolation Valve SI-173 (Shutdown Heat Exchanger AC-4A & 4B Outlet Cross Connect Valve) was locked shut. The valve was immediately restored to the open position. The licensee determined that, on September 9, 2006, when Procedure OI-SC-1 had last been performed, a procedure requirement to open Valve SI-173 had been inadvertently signed as completed without the valve actually being repositioned.

The inspectors determined that, had a failure of the operating Train A of shutdown cooling occurred, Train B would not have been available. Significant diagnosis would have been required during a postulated event in order to determine the cause of lack of flow. Further, licensee Procedure AOP-19, "Loss of Shutdown Cooling," Revision 12, which the operators would use to respond to such an event, did not require them to either verify or reposition Valve SI-173. The initial determination by operations personnel (i.e., that Train B of shutdown cooling had been operable while in the isolated condition) was questioned by the inspectors. Fort Calhoun Station's operability determination of the shutdown cooling train was later revised to reflect that it had in fact been inoperable.

Analysis. The inspectors determined that the failure to comply with Technical Specifications for the reactor coolant system was a performance deficiency. This finding was determined to be greater than minor in that it affected the "Configuration Control" attribute of the Mitigating Systems cornerstone. The inspectors evaluated this finding using Manual Chapter 0609, Appendix G, because the condition occurred and was identified during shutdown conditions. Using Checklist 2 the inspectors determined that the finding screened as Green because the condition did not increase the likelihood that a loss of decay heat removal would occur due to failure of the system itself. This finding has a crosscutting aspect in the area of human performance associated with decision making because operations personnel incorrectly concluded that the shutdown cooling header was operable.

Enforcement. Technical Specification 2.1.1.(3) requires, in part, that with "T_{cold} less than 210°F with fuel in the reactor and all reactor vessel head closure bolts fully tightened, at least two of the decay heat removal loops . . . shall be operable." Operable is defined in the Technical Specifications as "when it is capable of performing its specified function(s)." Contrary to the above, on September 10-12, 2006, only one train of shutdown cooling was operable. This violation of Technical Specification 2.1.1.(3) is being treated as a noncited violation, consistent with Section VI.A of the Enforcement Policy (NCV 05000285/2006004-02). This violation was entered into the licensee corrective action program as CR 200603965.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the USAR, procedure requirements, and Technical Specifications to ensure that the five surveillance activities listed below demonstrated that the SSCs tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms set points. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- July 27, 2006, observed the Independent Spent Fuel Storage Facility surveillance test MSLT-DSC-TriVis, "Helium Mass Spectrometer Leak Test Procedure" Revision FtC-0

- August 16, 2006, Surveillance Test IC-ST-MS-0031, "Channel Calibration of Steam Generator RC-2B Channel B Pressure Loop B/P-905," Revision 14
- August 18, 2006, review of the leak detection activities conducted in accordance with OP-ST-RC-3001, "Reactor Coolant System Leak Rate Test," during a period of slightly elevated leakage
- August 23, 2006, Surveillance Test IC-ST-RPS–0055, "Calibration of Power Range Safety Channel C," Revision 2
- August 29, 2006, In service Test SE-ST-MS-3005, "Main Steam Safety Valves Set pressure Using Trevitest Equipment," Revision 4

Documents reviewed by the inspectors are shown above.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors performed in-office reviews of revisions to the Fort Calhoun Station Emergency Plan, including Revision 13 to Section D, Revision 33 to Section H, and Revision 19 to Section J. The inspectors also reviewed Revisions 40 and 41 to Emergency Plan Implementing Procedure OSC-1, "Emergency Classification." The revisions were submitted between April and August, 2006. The revisions (1) added procedural direction for implementation of the requirements of 10 CFR Part 72 for a dry fuel storage program, (2) added new emergency action level (7.1) for damage to a loaded dry fuel cask confinement boundary, (3) revised protective action recommendation guidance to specify the criteria for a sheltering recommendation in lieu of an evacuation recommendation during short term (< 1 hour) radiological releases with limited dose projections, and (4) relocated one emergency alert siren a minor distance with the concurrence of the Department of Homeland Security.

The revisions were compared to their previous revisions, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, to the criteria of NEI 99-01, "Methodology for Development of Emergency Action Levels," Revision 2, and to the standards in 10 CFR 50.47(b) to determine if the revisions were adequately conducted following the requirements of 10 CFR 50.54(q). This review was not documented in a Safety Evaluation Report and did not constitute approval of licensee changes, therefore, these revisions are subject to future inspection.

The inspectors completed one sample during the inspection.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas (HRAs), and worker adherence to these controls. The inspectors used the requirements in 10 CFR Part 20, the Technical Specifications, and the licensee's procedures required by Technical Specifications as criteria for determining compliance. During the inspection, the inspectors interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspectors performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone
- Controls (surveys, posting, and barricades) of radiation, high radiation, and potential airborne radioactivity areas in the Reactor, Spent Fuel, and Auxiliary Buildings
- Radiation work permits, procedures, engineering controls, and air sampler locations
- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms.
- Barrier integrity and performance of engineering controls in two potential airborne radioactivity areas
- Adequacy of the licensee's internal dose assessment for any actual internal exposure greater than 50 millirem Committed Effective Dose Equivalent
- Physical and programmatic controls for highly activated or contaminated materials (non-fuel) stored within the spent fuel pool.
- Self-assessments, audits, licensee event reports, and special reports related to the access control program since the last inspection
- Corrective action documents related to access controls

- Radiation work permit briefings and worker instructions
- Adequacy of radiological controls such as, required surveys, radiation protection job coverage, and contamination controls during job performance
- Dosimetry placement in high radiation work areas with significant dose rate gradients
- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas
- Controls for special areas that have the potential to become very high radiation areas during certain plant operations
- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas
- Radiation worker and radiation protection technician performance with respect to radiation protection work requirements

The inspectors completed 20 of the required 21 samples.

b. Findings

Introduction. The inspectors reviewed two examples of a self-revealing, noncited violation of Technical Specification 5.11.1, in which workers failed to obtain a high radiation area access authorization and associated radiological briefing before entering into the area. The violation had very low safety significance.

Description. The first example occurred on March 26, 2005, when a worker received a dose rate alarm while participating in the movement of equipment cutters with radiation readings greater than 100 millirem per hour at 30 centimeters. An investigation into the dose rate alarm revealed the individual was briefed and authorized for work activities, which did not include entries into high radiation areas. The individual voluntarily assisted another work group with the cutter movement but did not consider the limitations of his prior briefing and the high radiation area access authorization. In addition, the radiation protection technician covering the work activity assumed all individuals in the work area were appropriately briefed and authorized for the work activity. The licensee enhanced pre-job briefings to include additional radiation protection staff and worker self and peer checking to verify appropriate authorizations and briefings were performed.

The second example occurred on September 16, 2006, when a worker received two dose rate alarms while working on two fire detectors in the overhead between the equipment hatch and the pressurizer cubicle. The work scope was discussed with radiation protection personnel at the containment control point but was not sufficiently communicated with the radiation protection technician providing the pre-job surveys. This led the radiation protection technician to only survey and evaluate the fire detector that was in an open area and not the second area. After completing work on the fire detector in the open area, the worker used the nearby cable trays to gain access to the second fire detector where he passed in close proximity to the safety injection line. The worker received two dose rate alarms (going to and returning from) the second fire detector. The worker then exited containment and reported the alarms to radiation protection. The worker's dose rate alarm was set at 40 millirem per hour, the peak dose rate seen by the electronic alarming dosimeter was 102 millirem per hour, and a survey of the safety injection line after the event identified 110 millirem per hour at 30 cm. The worker failed to obtain radiological conditions and access authorization for the second area entered.

Analysis. The failure to obtain high radiation area access authorization and associated radiological briefings before entering the area is a performance deficiency. This finding is greater than minor because it is associated with one of the cornerstone attributes (exposure/contamination control) and affects the Occupational Radiation Safety cornerstone objective, in that the failure to obtain high radiation area authorized access and associated radiological briefings resulted in additional personnel exposure. Using the Occupational Radiation Safety Significance Determination Process, the inspectors determined that this finding was of very low safety significance because it did not involve: (1) an ALARA finding, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess doses. Additionally, this finding had a crosscutting aspect in the area of human performance because the workers failed to use error prevention tools such as self and peer checking.

Enforcement. Technical Specification 5.11.1 states, in part, that in lieu of the "control device" required by 10 CFR 20.1601(a) and 20.1601(c), each high radiation area, as defined in 10 CFR 20.1601, shall be barricaded and conspicuously posted as a high radiation area and entrance thereto controlled by a Radiation Work Permit. Any individuals permitted to enter such areas shall be provided with a continuously integrating and alarming radiation-monitoring device and may enter after the dose rate levels in the area have been established and personnel are made knowledgeable of them. Contrary to Technical Specifications, workers entered high radiation areas without obtaining the required radiological briefing and were not specifically authorized to enter the areas. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program (Condition Reports CR 200501675 and CR 200604123), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000285/2006004-03, Failure to obtain high radiation area access authorization and associated radiological briefing.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20 and the licensee's procedures required by Technical Specifications as criteria for determining compliance. The inspectors interviewed licensee personnel and reviewed:

- Three outage work activities scheduled during the inspection period and associated work activity exposure estimates which were likely to result in the highest personnel collective exposures

- Interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups

- Integration of ALARA requirements into work procedure and radiation work permit (or radiation exposure permit) documents

- Exposure tracking system

- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding

- Workers use of the low dose waiting areas

- First-line job supervisors' contribution to ensuring work activities are conducted in a dose efficient manner

- Specific sources identified by the licensee for exposure reduction actions and priorities established for these actions, and results achieved against since the last refueling cycle

- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

- Self-assessments, audits, and special reports related to the ALARA program since the last inspection

- Corrective action documents related to the ALARA program and follow-up activities such as initial problem identification, characterization, and tracking

The inspectors completed 4 of the required 15 samples and 7 of the optional samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Occupational Radiation Safety Cornerstone

- Occupational Exposure Control Effectiveness

The inspectors reviewed licensee documents from January 1, 2005, through June 30, 2006. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in the licensee's technical specifications), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in NEI 99-02). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data. In addition, the inspectors toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 3, were used to verify the basis in reporting for each data element.

The inspectors completed the required sample (1) in this cornerstone.

Public Radiation Safety Cornerstone

- Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

The inspectors reviewed licensee documents from January 1, 2005, through June 30, 2006. Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded PI thresholds and those reported to the NRC. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data. PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 3, were used to verify the basis in reporting for each data element.

The inspectors completed the required sample (1) in this cornerstone.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Fire Protection Unresolved Item Review

a. Inspection Scope

As part of the unresolved item closeout inspection, the inspectors assessed: (1) the corrective actions implemented for each specific unresolved item, (2) the self assessment performed to evaluate the fire protection program progress and readiness for this inspection, (3) plans implemented related to manual actions for 10 CFR Part 50, Appendix R, Section III.G.2 areas.

The inspectors conducted this inspection through documentation review and interviews with engineering and licensing personnel.

b. Observations and Findings

The inspectors noted that the licensee had taken significant steps to identify the extent of condition related to the unresolved items identified in the August 2005 triennial fire protection inspection. However, the inspectors noted that the licensee had not completed their procedure revisions at the time of this inspection. Similarly, the licensee had not finalized the engineering review of the engineered safety feature actuations.

The self assessment performed in June 2006 provided critical recommendations of the fire protection organization's progress related to the unresolved items and the level of detail in the plan to resolve the large number of manual actions for Appendix R, Section III.G.2 areas that did not have exemptions in place. For example, the self-assessment noted that the plans for resolving the use of manual actions, as documented in CR 200601090 did not have sufficient detail to drive the issue to resolution.

.2 Problem Identification and Resolution for Radiation Protection

a. Inspection Scope

The inspectors evaluated the effectiveness of the licensee's problem identification and resolution process with respect to the following inspection areas:

- Access Control to Radiologically Significant Areas (Section 2OS1)
- ALARA Planning and Controls (Section 2OS2)

b. Findings

No findings of significance were identified.

.3 Routine Review of Identification and Resolution of Problems with a Operator Work Around

a. Inspection Scope

The inspectors chose one issue (one inspection sample) for more in-depth review to verify that the licensee personnel had taken corrective actions commensurate with the significance of the issue. The inspectors reviewed the corrective actions associated with this condition including the licensee's classification of the issue being an operator work around. The inspectors also performed a review of operator workarounds, control room deficiencies, and control room burden lists. The inspectors focused on the cumulative effects of the workaround on the reliability/availability of mitigating systems and the corresponding impact on operators to respond in a correct and timely manner to plant transients and accidents. The inspectors reviewed the deficiencies against the licensee's Procedure OPD-4-17, "Control Room Deficiencies, Operator Burdens, and Operator Workaround," Revision 16, that described the programs for handling workarounds and deficiencies. The following issue was evaluated:

- Review of CR 2005005837 Degraded FI-417, Flow Indicator for Cooling Water Flow from VA-1B

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000285/2005008-01: Failure to maintain the safety injection and refueling water tank valves free of fire damage

Introduction. The inspectors determined that the failure to have the cable separation required by 10 CFR Part 50, Appendix R, Section III.G.2, to the suction valves located between the safety injection and refueling water tank and the safety injection pumps would not have resulted in closure of the valves. The short that could result would not generate sufficient voltage to actuate the solenoid for the suction valves. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

Description. During the triennial fire protection inspection in August 2005, the team determined that a fire in Fire Area 20 could potentially cause loss of redundant trains of systems and equipment credited in the postfire safe shutdown analysis. Specifically, the safe shutdown analysis credited the use of Safety Injection Pumps SI-2A or SI-2B taking suction from the safety injection and refueling water tank.

The team had determined that: (1) the postfire safe shutdown analysis credited Valves LCV-383-1 and LCV-383-2 for the safety injection system to accomplish its shutdown function and at least one of the two valves must remain free of fire damage; (2) a single hot short on Cable EB3884 (Valve LCV-383-1) or Cable EA3890 (Valve LCV-383-2) could cause the associated valve to fail in the undesired (closed) position; and (3) the licensee had routed both cables in cable trays that are located less that 10 feet apart horizontally. The licensee initiated CR 200504001 to place this item into their corrective action program and had established an hourly fire watch for this fire area as an interim compensatory measure.

During this inspection, the inspectors: (1) reviewed Operability Evaluation for Valves LCV-383-1 and LCV-383-2, (2) verified that the indicating lamp had a 2000-ohm resistor, (3) verified that the solenoid had a maximum resistance of 885 ohms, and (4) verified the solenoid required 90 Vdc to actuate. The worst-case scenario resulted from a short from the close circuit to the solenoid actuation circuit that placed the indicating lamp and solenoid in series in the 125 Vdc circuit. Analyzing the circuit determined that the solenoid would draw 38.4 Vdc, which would not actuate the solenoid and inadvertently close the valves.

Analysis. Routing the cables for safety-related valves needed for postfire safe shutdown within 10 feet of each other was a performance deficiency for failure to meet the separation requirements specified in 10 CFR Part 50, Appendix R, Section III.G.2. This finding was determined to be of minor safety significance because it would not have impacted the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Specifically, a fire in Fire Area 20 did not have the potential to cause damage to circuits that could adversely affect the ability of the licensee to provide makeup to the reactor coolant system via the safety injection and refueling water tank.

Enforcement. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered this deficiency into their corrective action program as CR 200504001. The inspectors determined that the licensee had initiated Project Number FC 38203 in April 2006 to route one of the cables in a conduit or relocate to another fire area because of the continued noncompliance with 10 CFR Part 50, Appendix R, Section III.G.2.

.2 (Closed) Unresolved Item 05000285/2005008-02: Lack of an evaluation of fire-induced automatic actuation signals on a fire area basis

Introduction. The inspectors determined that the failure to evaluate fire-induced actuations of engineered safety feature actuation system sensors and cables as required by 10 CFR Part 50, Appendix R, Section III.G.2 would not have resulted in actuation of components needed for hot shutdown. The evaluation that was performed did identify circuits subject to spurious actuation needed for cold shutdown, which could be repaired within the 72 hours allowed. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

Description. During the triennial fire protection inspection in August 2005, the team determined that the safe shutdown analysis had not evaluated engineered safety feature actuation system automatic control systems or related instrumentation and cables that could have a significant impact on safety if damaged during a fire. For example, for Fire Area 20 the safe shutdown analysis credits the use of safety injection pumps taking suction from the safety injection and refueling water tank. However, if a recirculation actuation signal occurred because of fire damage, the discharge valves for the tank would close and the suction for the pumps could be transferred to a dry containment sump, which could damage the pumps. The licensee entered this finding into the corrective action program as CR 200503738 and established an hourly fire watch for this fire area as an interim compensatory measure.

During this inspection, the inspectors reviewed Calculation EA 06-008, "Engineered Safety Features Actuation System (ESFAS) Fire-Induced Failure Evaluation," Revision 0, and discussed the results with the fire protection engineer. Calculation EA 06-008 evaluated the circuits related to the re-circulation actuation signal, the containment spray actuation signal, the safety injection actuation signal, the containment isolation actuation signal, and the steam generator isolation signal. The inspectors determined that the evaluation appropriately identified each sensor and sensor cable for faults. The evaluation identified that many circuits needed for cold shutdown would require manual actions to resolve spurious operation and made corrective action recommendations. Some conclusions did not clearly indicate that the spurious operation would not affect achieving hot shutdown.

Consequently, the inspectors interviewed the fire protection engineer and reviewed Calculation EA-FC-89-055, "10 CFR Part 50, Appendix R, Safe Shutdown Analyses," Revision 12. This review confirmed that components affected were not required for a long period, were needed to achieve cold shutdown, and were being addressed in the update to Procedure AOP-06, "Fire Emergency," Revision 16. Consequently, the inspectors concluded that the potential circuit failures would have little effect on the ability of the licensee staff to achieve hot shutdown.

Analysis. The failure to evaluate engineered safety feature actuation systems for fire-induced circuit failures resulted in a performance deficiency for failure to meet the separation requirements specified in 10 CFR Part 50, Appendix R, Section III.G.2. This finding was determined to be of minor safety significance because it would not have impacted the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Specifically, the failure to evaluate fire-induced actuations, including the impact on safe shutdown, of the engineered safety feature actuation systems instrumentation and cables did not affect response activities to achieve hot shutdown.

Enforcement. This failure to comply with 10 CFR Part 50, Appendix R, Section III.G.2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered this deficiency into their corrective action program as CR 200503738. At the time of this inspection, the licensee had recently received the evaluation from their contractor and had not completed all of their engineering reviews.

.3 (Closed) Unresolved Item 05000285/2005008-03: Inadequate procedure for implementing the fire protection program as required by Technical Specification 5.8.1.c.

Introduction. The inspectors identified a Green NCV of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, Procedure SO-G-28, "Station Fire Plan," Revision 61, did not provide adequate instructions for operators to mitigate the effects of fire damage.

Description. During the triennial fire protection inspection in August 2005, the team identified several deficiencies related to the postfire safe shutdown procedures. Operators used Procedure AOP-06, "Fire Emergency," Revision 11 to implement the detailed response when evacuating the control room, including manual actions. Procedure SO-G-28 provided instructions for operators to mitigate the effects of fire damage to safe shutdown equipment in plant areas other than the control room and the cable spreading room. Procedure SO-G-28, Attachment 14, "Restoration of Safe Shutdown Conditions in the Event of a Fire," described the fire areas that required the use of manual operator actions to mitigate fires in those areas for fires other than a control room evacuation.

As a result of tabletop walkthroughs and simulator evaluations using Procedures AOP-06 and SO-G-28, the team had determined that Procedure SO-G-28: (1) was not referred to in Procedure AOP-06; (2) did not direct operators to enter Attachment 14 nor did operators refer to the attachment; (3) did not identify the diagnostic instrumentation that may be relied upon for a fire in each fire area; (4) main body did not provide operators detailed information identifying the manual actions to be performed in response to a fire; (5) did not provide operators information as to which, if any, manual actions are time critical; and (6) for Fire Area 43, required operators to re-enter the area if a fire had occurred to close Manual Valve IA-3119. In summary, the team concluded that manual actions were not reliable and feasible because of the lack of diagnostic instruments being identified, the poor coordination among the various procedures, and operator's lack of familiarity with Procedure SO-G-28, Attachment 14, which identified key manual actions needed.

During this inspection, the inspectors identified postfire safe shutdown components in Fire Areas 20, 32 and 43 which required manipulation to safely shutdown the reactor for fires outside the control room. For Fire Area 20 (Room 69), the inspectors concluded that Procedure SO-G-28 provided appropriate guidance through redirection to AOP-32, "Loss of 4160 Volt or 480 Volt Bus Power," Revision 10, and EOP-20,"Functional Recovery Procedure," Revision 18. The third action in this fire area involved valving in raw water to the control room HVAC upon loss of normal cooling water. The inspectors considered this action low risk since the control room heat-up would be gradual. However, the inspectors noted that, at the time of this finding, the procedure remained deficient in that it had not identified the instruments that remained operable.

For Fire Area 32 (Room 19), Procedure SO-G-28, Attachment 14 failed to list operable diagnostic instrumentation and actions needed to respond to spurious operation of components powered from the 4 kV busses. Similarly, for Fire Area 43 (Room 81), Procedure SO-G-28, Attachment 14, failed to identify operable diagnostic instruments and required operators to re-enter the room when it may not have been habitable. The inspectors determined that the references to other emergency and abnormal operating procedures provided appropriate implementing instructions.

The licensee had entered these deficiencies into their corrective action program as CRs 200503731, 200504006, and 200504203. The inspectors verified that the licensee had revised Procedure SO-G-28 to refer to Attachment 14 and to include the operable diagnostic information in Attachment 14. In addition, the licensee had initiated revisions to Procedure AOP-06 to incorporate the guidelines contained in Procedure SO-G-28 and provided more detailed mitigation steps. Upon final approval all guidance would be contained in Procedure AOP-06. This finding had a cross-cutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement manual actions for postfire safe shutdown.

Analysis. The failure of Procedure SO-G-28 to provide adequate instructions to operators to perform manual actions to mitigate the consequences of fire damage and ensure hot shutdown could be achieved was a performance deficiency for failure to meet Technical Specification 5.8.1.c. Specifically, Procedure SO-G-28, Attachment 14, failed to list operable diagnostic instrumentation, actions needed to respond to faults on 4 kV busses, and had operators re-enter an area without knowing it would be safe. This deficiency was more than minor in that it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Consequently, the inspectors evaluated these deficiencies using Manual Chapter 0609, Appendix F

The actions for Fire Area 32 (Room 19) were postfire safe shutdown functions in the auxiliary building related to maintaining reactor coolant system inventory (inadvertent operation of the power-operated relief valves), had existed for more than 30 days, and had a moderate degradation rating. Consequently, the issue did not screen out in Phase 1. During the Phase 2 evaluation, the inspectors identified the ignition sources (air compressor motor, air compressor oil, turbine-driven auxiliary feedwater pump oil, electrical control cabinet for the air compressor, motor driven auxiliary feedwater pump motor) and the targets (thermoset cable). One component, compressor electrical cabinets, did not screen out and required use of the NUREG-1805 model for a room with forced ventilation to determine the hot gas layer temperature. Because of the room volume and the forced ventilation flow rate, the electrical cabinet did not generate sufficient heat in the hot gas layer to damage the thermoset cables.

The actions for Fire Area 43 (Room 81) were postfire safe shutdown functions in the auxiliary building related to maintaining a heat sink (operability of auxiliary feedwater), had existed for more than 30 days, and had a moderate degradation rating. Consequently, the issue did not screen out in Phase 1. During the Phase 2 evaluation, the inspectors identified the ignition sources (ventilation unit motors and wood staged in a metal gang box) and the targets as the E/P converter for the auxiliary feedwater air-operated valves and the electric panels for the main steam code safeties. One component, electric cables to the E/P converter for the air-operated auxiliary feedwater valve, did not screen out and required use of the NUREG-1805 model for a room with forced ventilation to determine the hot gas layer temperature. Because of the room volume and the forced ventilation flow rate, the wood in the metal gang box (assumed the wood was not enclosed) did not generate sufficient heat in the hot gas layer to damage the cables to the E/P converter.

However, because the potential for fire damage did not exist in Fire Areas 32 and 43 as determined by the Appendix F, Step 2.3 Phase 2 significance determination process for each fire area, the inspectors concluded that this finding was of very low safety significance (Green).

Enforcement. Technical Specification 5.8.1.c. requires that written procedures and administrative policies shall be established, implemented and maintained covering fire protection program implementation. Procedure SO-G-28 provided the guidance to operators, including manual actions, to achieve postfire safe shutdown. Inspection Procedure 71111.05T, Enclosure 2, specified the criteria that must be met for manual actions to be considered feasible without an approved exemption to 10 CFR Part 50, Appendix R. Contrary to the above, the inspectors determined that Procedure SO-G-28 failed to meet the following manual action feasibility criteria: (1) procedure guidance failed to identify exactly what manual actions were needed, (2) diagnostic instruments that remained operable for a fire in each fire area were not identified, and (3) directed operators to the area without any guidelines for when it would be safe to manipulate a component in the same area. Because this finding is of very low safety significance and has been entered into the corrective action program (CR 200504203), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000285/2006004-04, Failure to implement reasonable and feasible manual actions.

.4 (Closed) Unresolved Item 05000285/2005008-04: Inadequate fire safe shutdown procedure for control room evacuation

Introduction. The inspectors identified a Green NCV of Technical Specification 5.8.1.c for failure to have an adequate procedure to implement postfire safe shutdown actions. Specifically, simulated operator actions during a walkthrough of Procedure AOP-06, "Fire Emergency," Revision 12, could not be performed in the time specified in engineering calculations nor were all appropriate steps specified.

Description. During the triennial fire protection inspection in August 2005, the team identified, during timed walkthroughs of AOP-06, Section II, "Control Room Evacuation," that the procedure had inadequate guidance. The team determined that Procedure AOP-06, Section II: (1) identified establishing control for alternate shutdown at AI-179, Auxiliary Feedwater Panel, and AI-185, Alternate Shutdown Panel, (2) failed to identify a time frame for establishing auxiliary feedwater whereas calculations specified time frames as short as 12 minutes, and (3) prior to establishing control at Panel AI-179, required the communicator to manually throttle Valves HCV-1107B, "Steam Generator RC-2A Auxiliary Feedwater Inlet Valve," and HCV-1108B, "Steam Generator RC-2B Auxiliary Feedwater Inlet Valve," to 75 percent closed.

Further, the team determined that: (1) the communicator can easily meet the time line in the calculations with the valves in their normally closed position. However, if the valves receive a spurious open signal prior to throttling, interviews with operators indicated that the valves may not be able to be manually throttled, and (2) Procedure AOP-06, Section II, identified no contingency actions to throttle the valves closed or for establishing control at Panel AI-179 if the valves were not throttled closed.

During this inspection, the inspectors verified the licensee had corrected the deficiencies identified by the team. Further, the licensee entered this finding into the corrective action program as CR 200503731 and revised Procedure AOP-06 to include contingency actions should the valves open prior to completion of manual throttling. This finding had a crosscutting aspect in the area of human performance because the licensee did not ensure complete, accurate and up-to-date procedures needed to implement the actions.

Analysis. The failure of Procedure AOP-06 to provide sufficient guidance was a performance deficiency for failure to meet Technical Specification 5.8.1.c. Specifically, the procedure failed to ensure that response personnel had the appropriate guidance and equipment to allow them to carry out the functions of limiting auxiliary feedwater flow to the steam generators when needed. This deficiency was more than minor in that it had the potential to impact the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to external events (such as fire) to prevent undesirable consequences. Consequently, the inspectors evaluated these deficiencies using Manual Chapter 0609, Appendix F.

Because of other actions that would, likely, have been taken, the inspectors concluded this issue had a low degradation rating and, therefore, the inspector concluded the issue had very low safety significance in the Phase 1 evaluation.

Enforcement. Technical Specification 5.8.1.c. requires that written procedures and administrative policies shall be established, implemented and maintained covering fire protection program implementation. Procedure AOP-06, Section II, provided the guidance to operators, including manual actions, to achieve postfire safe shutdown for a control room evacuation. Inspection Procedure 71111.05T, Enclosure 2, specified the criteria that must be met for manual actions to be considered feasible without an approved exemption to 10 CFR Part 50, Appendix R. Contrary to the above, the inspectors determined that Procedure AOP-06, Section II, failed to ensure that manual operation of auxiliary feedwater valves would be accomplished prior to the times specified in engineering calculations and failed to ensure sufficient guidance and tools existed for equipment operators to accomplish the task. Specifically, the procedure specified no time limit, and the communicator, during timing evolutions, indicated that if the valves were open the 12-minute time limit would not be met and he had no way of informing the control room supervisor because he did not carry a radio. Because this finding is of very low safety significance and has been entered into the corrective action program (CR 200503731), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000285/2006004-05, Inadequate alternate shutdown procedure.

.5 (Closed) LER 05000285/2006002-00, Inadequate Design Control Results in Potentially Insufficient Auxiliary Feedwater Flow

The details of this condition are discussed in Section 4OA7 of this report. This LER is closed.

4OA6 Meetings

Exit Meeting Summary

The inspectors discussed the preliminary results of the fire protection unresolved item review with Mr. J. Reinhart, Site Director, and other members of licensee management on July 21, 2006. The inspectors returned proprietary information examined during the inspection to the licensee. The inspectors conducted a telephonic exit meeting with Mr. Joe McManis, Manager, Nuclear Licensing, and other licensee personnel on August 18, 2006. Licensee management acknowledged the inspection results.

On August 10, 2006, the operator licensing inspectors conducted a debrief meeting to present the licensed operator requalification inspection results to the Licensee's management team. During the debrief, the inspectors informed the management team they had obtained permission to retain copies of six medical certification forms containing privacy information act material. It had also been agreed this material would be shredded upon issuance of the inspection report. The licensee was informed that a final exit for the inspection would be conducted after the requalification program was completed and the NRC had reviewed the final results. On September 20, 2006, a final exit, which described the inspection results, was conducted by the inspectors via telephone with Mr. D. Weaver, Supervisor of Operations Training. The licensee acknowledged the findings presented in both the briefing and the final exit meeting. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On August 11, 2006, the inspectors presented the safety evaluation and permanent plant modifications inspection results to Mr. J. Reinhert, Site Director, and other members of the staff who acknowledged the findings. While some proprietary information was reviewed during this inspection, no proprietary information was included in this report.

On August 30, 2006, the inspectors presented the results of the emergency plan change inspection to Mr. C. Simmons, Supervisor, Emergency Preparedness. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On September 22, 2006, the inspectors presented the occupational radiation safety inspection results to Mr. J. Reinhart, Site Director, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

The results of the resident inspector activities were presented to Mr. J. Reinhart, Site director, and other members of licensee management on October 6, 2006. The inspectors confirmed that proprietary information examined during the inspection period was returned to the licensee. Licensee management acknowledged the inspection findings.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- Title 10 CFR Part 50, Appendix B, Section III, "Design Control," states, in part, that "Measures shall also be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety related functions of the SSCs." Contrary to the above, the electrical power supply to flow transmitter FT-1368 (Motor Driven Auxiliary Feedwater Pump Suction Flow Transmitter) was not safety-related. During an event the flow transmitter and associated recirculation valve may not perform its design function consequently challenging the ability of the Motor Driven Auxiliary Feedwater Pump to provide cooling to the steam generators. This finding only had very low safety significance because it was a design or qualification deficiency confirmed not to result in loss of operability. This finding was identified in the licensee's corrective action program as CR 200602855 and was reported as LER 05000285/2006-002-00.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Bannister, Plant Manager
B. Blessie, Supervisor, Operations Engineer
D. Buell, Fire Protection Engineer
T. Byrne, Licensing Engineer (Title 10 CFR 50.59 Program Coordinator)
G. Cavanaugh, Supervisor, Regulatory Compliance
S. Cofaul, ALARA Technician, Radiation protection
M. Core, Manager, System Engineering
H. Faulhaber, Division Manager, Engineering
M. Ferm, Manager, Shift Operations
W. Goddell, Nuclear Training Manager
D. Guinn, Licensing Engineer
W. Hansher, Lead, Nuclear Safety Review
R. Haug, manager, Radiation Protection
K. Hyde, Supervisor, mechanical Engineering
R. Jaworski, Licensing Engineer
G. Labs, Simulator Supervisor
D. Lakin, Manager, Corrective Action Program
T. Maine, Supervisor, Radiation Protection
E. Matzke, Compliance Engineer
J. McManis, Manager, Licensing
T. Nellenbach, Manager, Operations
M. Pohl, Principal Reactor Engineer, Operations
M. Quinn, Nuclear Engineering and Computing Projects Supervisor
J. Reinhart, Site Director
R. Short, Manager, NSSS Replacement Components
C. Simmons, Supervisor, Emergency Preparedness
M. Tesar, Division manager, Nuclear Support Services
J. Tills, Manager, Maintenance
D. Travsch, Manager, Quality
D. Weaver, Operations and Technical Training Supervisor
J. Willett, Principle Reactor Engineer Fuels, Operations
C. Williams, Supervisor, Radiation Protection

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Open and Closed

05000258/2006004-01	NCV	Failure to Translate Replacement Pressurizer Weight Into Design Calculations (Section 1R17)
05000285/2006004-02	NCV	Failure to Maintain Shutdown Cooling Train Operable as Required by Technical Specification 2.1.1.(3) (Section 1R20)

05000285/2006004-03	NCV	Failure to Obtain High Radiation Area Access Authorization and an Associated Radiological Briefing (Section 2OS1)
05000285/2006004-04	NCV	Failure to Implement Reasonable and Feasible Manual Actions (Section 4OA5.3)
05000285/2006004-05	NCV	Inadequate Alternate Shutdown Procedure (Section 4OA5.4)

Closed

05000285/2005008-01	URI	Failure to Maintain the Safety Injection and Refueling Water Tank Valves Free of Fire Damage (Section 4OA5.1)
05000285/2005008-02	URI	Lack of an Evaluation of Fire-Induced Automatic Actuation Signals on a Fire Area Basis (Section 4OA5.2)
05000285/2005008-03	URI	Inadequate Procedure for Implementing the Fire Protection Program as Required by Technical Specification 5.8.1.c. (Section 4OA5.3)
05000285/2005008-04	URI	Inadequate Fire Safe Shutdown Procedure for Control Room Evacuation (Section 4OA5.4)
05000285/2006002-00	LER	Inadequate Design Control Results in Potentially Insufficient Auxiliary Feedwater Flow (Section 4OA7)

LIST OF DOCUMENTS REVIEWED

Section 1R02: Evaluations of Changes, Tests, or Experiments

10 CFR 50.59 Evaluations

FC-071145, LTR-RCPL-04-75, OPPD Replacement Pressurizer
EC 33109
EC 38303
FC-154B for EC-31589
FC-154B for EC-38331
10 CFR 50.59 Screenings

EC 33116
FC-154A, EC-33105
EC 33117
EC 33109
EC-154A for EC-31589 (RSG)
FC-154A for EC-31589 (RSG Type C-6 Nozzle Dams)
FC-154A for EC-33106
EC 33153
EC 25764 for USAR Section 14 Revision
EC 33104

Applicability Determinations

FC-68C for EC 33105
EC 33116
EC 33117
EC 33109
EC 33115
FC-68C for EC 31589
FC-68C for EC 33106
EC 33153
EC 25764 for USAR Section 14 Revision
EC 33104

Procedures

NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews"

Section 1RO4: Equipment Alignment

Licensee Procedure OI-SFP-1, "Spent Fuel Pool Cooling Normal Operations," Revision 29

Licensee Procedure ARP-CB-1,2,3/A1, "Annunciator Response Procedure A1 Control Room Annunciator A1", Revision 26

Drawing 11405-M11, "Auxiliary Coolant Spent Fuel Pool Cooling System Flow Diagram P&ID," Revision 52

Section 1RO5: Fire Protection

Standing Order SO-G-28, "Station Fire Plan," Revision 66

Standing Order SO-G-102, "Fire Protection Program," Revision 7

Abnormal Operating Procedure AOP-6, "Fire Emergency," Revision 17

USAR, Section 9.11, "Fire Protection Systems"

Section 1RO6: Flood Protection Measures

Probabilistic Risk Assessment Summary Notebook, Revision 4

Individual Plant Examination Submittal, dated December 1993

Section 1R11: Licensed Operator Requalification Program

Open Simulator Discrepancy Reports (All)
Closed Simulator Discrepancy Reports Summary from January 2006 thru May 2006
Simulator Configuration Review Group (SCRG) meeting minutes for 2005
Simulator Annual Performance Test book for 2006

Simulator Steady State Testing Packages for 100% and 30% Power
Simulator Transient Testing Packages for Tests Three, Eight, and Ten
Current Simulator Differences List
Core physics testing packages for simulator, Cycle 23.
Low Power Physics Test data from the plant, Cycle 23.
Simulator Modification Procedures
Verification and Validation Procedures
Operator licensing tracking system active operator licenses (R4 OLTS report)
Current operator license list from Fort Calhoun Station
AP 21-001, Conduct of Operations, Rev. 35
AI 21-100, Operations Guidance and Expectations, Rev. 6
AI 30B-005, Conduct of Simulator Activities for Licensed Operator Training, Rev.8A
AP 30B-001, Licensed Operator Requalification Training Program, Rev. 7A
AP 30B-006, Shift Engineer/Shift Technical Advisor Requalification Training Program, Rev. 3
DTI 204, Operator Requalification JPM Preparation, Validation, and Administration

Section 1R12: Maintenance Effectiveness

Condition Reports

200503725	200505469	200600189	200601570
200603628			

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

Standing Order SO-O-21, "Shutdown Operations Protection Plan," Revision 25

Condition Report 200602982

Control Room Operating Logs, dated July 16 and July 17, 2006

Risk evaluation and risk management actions per e-mail from John Fluehr, OPPD dated July 18, 2006

Section 1R17B: Permanent Plant Modifications

Plant Modifications

Number	Title	Revision
EC 32447	Replacement Pressurizer	0
EC 33105	Pressurizer Replacement	0
EC 33106	Steam Generator Large Bore Piping	0
EC 33116	Pressurizer Heater Cable Replacement	0
EC 33109	Containment Opening	0
EC 31589	Fort Calhoun - Replacement Steam Generators (Component)	0

EC 33153	Fort Calhoun - Replacement Reactor Vessel Head (Component)	0
EC 33104	Steam Generator Replacement	0

Engineering Changes

Number	Title	Revision
EC 38331	Safety Injection Phase Performance for Safety Injection and Containment Spray Systems Calculation No. FC07077	0
EC 33115	Temporary Transformer/RC-3A Tie-In	0
EC 33117	Replacement Pressurizer Instrument Modification	0
EC 38303	Recirculation Phase System Performance for Safety Injection and Containment Spray Systems	0

Drawings

ISO WD-2072, Sh.1	File 8939	9
ISO CH-2049, Sh. 1	File 8187	9
04-30991-01	Y-Globe Valve, Socket Ends...Size 2, Class 1878	0
11405-S-39	Reactor Plant Ground Floor Plan El. 1013'-0" Reinf. Sh.1	5

Calculations

FC 03122	10" Surge Line Break Effect on Pressurizer Slab and Walls below Pressurizer Compartment	1
FC 07085	Pressurizer Anchor Bolts	0
FC07172 (Bechtel Calculation 25036-C-029)	Evaluation of Containment Structure for Construction Opening	0
Combustion Engineering Calculation 0-SEC-15	Determination of Pressurizer Heater Capacity	7/12/67
FC 06974 (Areva Calculation) 32-5046461-00	FCS RSG – Decay Heat Removal Cap. In Nat. Circ. Analysis	4/1/04
32-5046526-00	FCS RSG – Loss of Load to Both Steam Generators Analysis	10/22/04

FC 07186	Fort Calhoun Scaling Calculation for Replacement Pressurizer Level Transmitters	3
CN-RVHP-05-59	Fort Calhoun Head Lift NUREG-0612 Evaluation	1
WB-CN-ENG-05-32	Fort Calhoun - Cap Screw Design	1
FC 03231	FCS RCS Support Validation	0

Procedures

Number	Title	Revision
SO-G-21	Standing Order Modification Control	78
PED-GEI-3	Preparation of Modification	42
PED-QP-2	Configuration Change Control	29
PSC Procedure F&Q 15.0	Precision Surveillance Corporation Field and Quality Control Procedure for Tendon Re-stressing	1
PSC Procedure F&Q 15.2	Precision Surveillance Corporation Field and Quality Control Procedure for Bearing Plate Concrete Inspection	0

Miscellaneous Documents

Number	Title	Revision
NPM-210	Nuclear Procurement Manual	13
N/A	Licensing Amendment Request Status Log	15
SA-06-23	Self Assessment Report, 10CFR50.50 Implementation	7/27/06
N/A	Watlow Pressurizer Heater Accelerated Life Test Status Report	7/12/06
FCSG-23	10 CFR 50.59 Resource Manual	5
FC-07145, LTR-RCPL-05-115	Final Design Licensing Report for the OPPD Replacement Pressurizer	0
FCP-KBS-05-00014	Accelerated Life Test Procedure for Heaters of RPZR	1
FCP-KBS-06-0002	RPZR Heater Accelerated Life Test Results for Short Term Electrical Failures	0
LIC-05-0107	Fort Calhoun Station Unit No. 1 License Amendment Request, "Updated Safety Analysis Report Revision for Radiological Consequences Analysis for Replacement NSSS Components"	10/31/05

NUREG 0800	Standard Review Plan for the Review of Safety Reports for Nuclear Power Plants	2
AREVA Engineering Information Record	FCS RSG - Control System Evaluation, 51-5050728-01	1
EA-FC -02-028	Appendix K Power Uprate Evaluation, Section 5	0
Email from Alan Wang (NRC) to Leonard M. Willoughby (NRC)	AST Accident Dose - Criteria for Categorical Exclusion	8/10/06
LTR-RCPL-05-135	Final Design Licensing Report for the OPPD Replacement Reactor Vessel Head and Rapid Refueling Package (RRVH/RRP)	0
RFP 1758	Technical Specification for Design of Mirror Insulation for the Replacement Reactor Vessel Head for Omaha Public Power District, Fort Calhoun Station	0
MR FC-79-15	Replacement of Reactor Pressure Vessel and Seismic Skirt Insulation; Appendix 7.2, Section H, Contract 1318 Technical Specification	4/82

Condition Reports

CR 200603413	CR 200402963	CR 200504555	CR 200600896
CR 200600624	CR 00602152	CR 200601839	CR 200603179
CR 200504214	CR 200600395	CR 200603252	CR 200504503
CR 200402637	CR 200504503	CR 200500408	CR 200600750
CR 200602255	CR 200403490	CR 200601815	CR 200505022
CR 200600454	CR 200602693	CR 200603374	CR 200401985
CR 200503149	CR 00600195	CR 200501970	

Section 1R19: Postmaintenance Testing

Work Order 00217639-01, Replace Filter or Regulator Assembly for IA-HCV-2883B-FR

Procedure SP-CP-08-480-1B3A, “Calibration of Protective Relays for 480-1B3A Bus,” Revision 14

Work Order 00218435-01, Replace Steam Generator RC-2A Blow-down to Blow-down Tank FW-7 Control Valve HCV-1390

Work Order 00244394-01, Repair the Fire Main Rupture between FP-106 and FP-104

Section 1R20: Refueling and Other Outage Activities

Shutdown Safety Advisor’s Log dated September 13, 2006

Technical Specifications, Definitions Section, page 5

OI-SC-1, "Shutdown Cooling System," Revision 42

Drawing D-4768, "Primary Plant Simplified Flowpath Diagram," Revision 5

Abnormal Operating Procedure AOP-19, "Loss of Shutdown Cooling," Revision 12

Root Cause Analysis Report for CR 200603965

Section 2OS1: Access Controls to Radiologically Significant Areas (71121.01)

Audits, Self-Assessments, and Surveillances

Quality Assurance Audit Report No. 49/58
Self-Assessment SA-06-02
Surveillance Report 58(3)-0506

Condition Reports

200500993, 200501625, 200501675, 200600870, 200601277, 20061866, 200603848, 200604123

Procedures

RP-202	Radiation Protection Radiological Surveys, Revision 26
RP-204	Radiological Area Controls, Revision 44
RP-208	Radiography, Revision 10
RP-602	Radiation Protection Personnel Dosimetry Issuance and Change-out, Revision 20
RP-608	Dose Calculations from Contamination, Revision 11
RPI-13	Radiological Posting Standards, Revision 2
SO-G-92	Conduct of Infrequently Performed Procedures, Revision 9
SO-G-101	Radiation Worker Practices, Revision 30
SO-O-47	Spent Fuel Pool Inventory Control, Revision 6

Radiation Work Permits

06-3001, 06-3520, 06-3533, and 06-3541

Sample Results and Surveys

Air Sample Form and Results for RWP 06-3541 on 09/21/06
Survey Numbers: 05-1173, 06-1088

Miscellaneous

2005 DAC-Hour Tracking Summary
Dose Rate Alarm Report
Shift Outage Manager's Reports

Section 2OS2: ALARA Planning and Controls (71121.02)

Audits, Self-Assessments, and Surveillances

Quality Assurance Audit Report No. 49/58
Self-Assessment SA-06-02
Surveillance Report 58(3)-0506

Condition Reports

200504826, 200505725, 200602354

Radiation Work Permits

06-3520, 06-3533, and 06-3541

Procedures

RP-301 ALARA Planning / RWP Development and Control, Revision 26

Miscellaneous

Shift Outage Manager's Reports

Section 4OA1: Performance Indicator Verification (71151)

Procedures

NOD-QP-40 NRC Performance Indicator Program, Revision 2

Miscellaneous

2005 Abnormal Batch Liquid and Gaseous Release Summary
2005 Batch Liquid and Gaseous Release Summary
2005 Liquid Effluents Continuous Mode
Surveillance Report Numbers: 63(3)-0606 and 63(3)-1105

Section 4OA5: Other Activities (71111.05T)

Procedures

AOP-06, "Fire Emergency," Revisions 15 and 16
AOP-32, "Loss of 4160 Volt or 480 Volt Bus Power," Revision 10
EOP-06, "Loss of All Feedwater," Revision 12
EOP-20, "Functional Recovery Procedure," Revision 18
FCSG, "Performing Risk Assessments,"
OPD-2-06, "Operations Department Duties and Responsibilities," Revision 21
SO-G-28, "Station Fire Plan," Revisions 61 and 65
SO-—100, "Conduct of Maintenance," Revision 41
SO-O-1, "Conduct of Operations," Revision 69

Drawings

11405-—253, "Flow Diagram, Steam Generator Feedwater and Blowdown," Sheet 4, Revision 3

11405-S-64, "Auxiliary Building Sections," Sheet 2, Revision 4

Calculations

EA 06-008, "Engineered Safety Features Actuation System (ESFAS) Fire-Induced Failure Evaluation," Revision 0

EA-FC-89-055, "10 CFR Part 50, Appendix R, Safe Shutdown Analysis," Revisions 11 and 12

EA-FC-97-001, "Fire Hazards Analysis (FHA) Manual," Revision 11

EA-FC-97-044, "10 CFR Part 50, Appendix R, Cable Identification," Revision 4

FC 05814, "UFHA Combustible Loading," Revision 9

Condition Reports

200204316	200503731	200503738	200503750	200503979	200504001
200504006	200504203	200601090			

Miscellaneous

Engineering Information Record 51-9016709-00, "Fort Calhoun Station Transient Analysis, Manual Action Timeline and Feasibility Study," dated June 21, 2006

Fisher-Rosemount Vendor Manual, "Type 657 Diaphragm Actuator, Sizes 30 - 70 and 87"

LIST OF ACRONYMS

CFR	*Code of Federal Regulations*
CR	Condition Report
NCV	noncited violation
NRC	Nuclear Regulatory Commission
SSC	Structure, System and Component
USAR	Updated Safety Analysis Report

U.S.NRC

UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

RN0109

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
REGION IV VISIT
August 14, 2007

-AGENDA-

Time	Topic	Presenter	Time Allotted
8:30 - 9:00 am	Region IV Overview and Challenges	Dr. Mallett P. Gwynn	30 minutes
9:00 - 9:30	Knowledge Management	J. Lopez R. Caniano	30 minutes
9:30 - 9:50	Reactor Oversight Process (ROP) Case Study #1	J. Hanna	20 minutes
9:50 - 10:10	ROP Best Practices	M. Hay	20 minutes
10:10 - 10:20	BREAK	-	10 minutes
10:20 - 10:40	ROP Case Study #2	W. Walker	20 minutes
10:40 - 11:10	ROP Case Study #3	G. Warnick	30 minutes
11:10 - 12:10	LUNCH	-	1 hour
12:10 - 12:40 pm	Incident Response Center Tour	L. Howell	30 minutes
12:40 - 1:05	Independent Spent Fuel Storage Installations and Decommissioning	Dr. Spitzberg	25 minutes
1:05 - 1:35	Safety Culture	L. Smith R. Caniano	30 minutes
1:35 - 2:05	Component Design Basis Inspections	G. Replogle	30 minutes
2:05 - 2:20	BREAK	-	15 minutes
2:20 - 3:30	ROP Roundtable Discussion ACRS Questions and Answers	T. Gody K. Clayton P. Elkmann G. Warnick G. Replogle D. Loveless J. Drake	1 hour 10 minutes
3:30 - 3:50	Closing Remarks	Dr. Mallett P. Gwynn	20 minutes

RIV CONTACT: Brian Tindell, bwt@nrc.gov or (817) 860-8244
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ACRS Visit to Region IV Attendees

ACRS Members

Dr. William Shack, ACRS Chairman
Dr. Mario Bonaca, ACRS Vice Chairman
Otto Maynard, ACRS Operations Sub-Committee Chairman
Dr. Graham Wallis, ACRS Member
Dr. Michael Corradini, ACRS Member
Dr. George Apostolakis, ACRS Member
Dr. Said Abdel-Kahlik, ACRS Member-at-Large

ACRS Staff

David Bessette, ACRS Staff
Maitri Banerjee, ACRS Staff
Jamila Perry, ACRS Staff
Girija Shukla, ACRS Staff

Region IV Staff

Bruce Mallett, Regional Administrator
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Roy Caniano, Deputy Director, Division of Reactor Safety
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Michael Hay, Chief, Projects Branch C
Linda Howell, Chief, Response Coordination Branch
Linda J. Smith, Chief, Engineering Branch 2
Dr. D. Balir Spitzberg, Chief, FC & D Branch
David P. Loveless, Senior Reactor Analyst
John D. Hanna, Senior Project Engineer
George Replogle, Senior Project Engineer
Kelly Clayton, Senior Operations Engineer
Wayne Walker, Senior Project Engineer
Greg Warnick, Senior Resident Inspector
Joseph L. Lopez, Human Resources Management Specialist
James F. Drake, Operations Engineer
Paul J. Elkmann, Emergency Preparedness Analyst

Office of NRR Staff

F. Paul Bonnett, Senior Reactor Analyst

Members of the Public

Carl Corbin, STARS Regulatory Affairs, Luminant Power, Comanche Peak
Fred Madden, Director, Oversight and Regulatory Affairs, Luminant Power, Comanche Peak
Michael McBrearty, Nuclear Regulatory Affairs Division, San Onofre Nuclear Generating Station

U. S. Nuclear Regulatory Commission
Region IV

Bruce S. Mallett
Regional Administrator

- **Darrell White** – Office of Investigations
  - Lynda Baker, Sec'y
  - #Lydia Garcia, Clerk
  - Mike FitzGibbon
  - Crystal D. Holland
  - JoAnn McArthur
  - Kevin Pryer
  - John Oglesby, Jr.

Thomas P. Gwynn
Deputy Regional Administrator

- Lucy Owen, Sec'y
- Judy Kilcrease, Sec'y

Victor L. Dricks – Public Affairs Officer

William A. Maier – Regional State Liaison Officer

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- Tom Andrews
- Gregory Ahern
- Fangie Jones
- Gerald Walg
- Beth Alfrerink
- Binesh Tharakan
- ++Hailey Swinehart

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- Judith Walker, AC
- Michael Vasquez, Sr. Enf Spec.
- Christi Maier, ES
- Mark Haire, ES
- +Michael Bloodgood
- ++Chris Speer

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- Sue Triffletti, Sec'y
- Shirley Gillum, Sec'y

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- Colleen Murnahan
- Roberto Torres
- Rachel Browder

Vivian Campbell – Chief, Nuclear Materials Inspection Branch
- Bob Brown
- Larry Donovan
- Janine Katanic
- Richard Leonardi
- Christi Maier
- Ramon (Rick) Munoz
- James Thompson,Jr.
- Tony Gaines
- Linda Gersey
- Jason Razo

Blair Spitzberg – Chief , Fuel Cycle & Decommissioning
- Scott Atwater
- Bob Evans
- Vince Everett
- Emilio Garcia
- Ray L. Kellar

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- Tracy Karl, Sec'y
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- Mike Runyan, SRA
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- Greg Tutak

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- Jim Adams
- Ray Azua
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- Samuel Graves
- Breck Henderson
- Ron Kopriva
- Shiattin Makor
- Jared Nadel
- Elizabeth Owen
- John Reynoso
- Scott Rutenkroger
- Wayne Sifre
- *Lee Ellershaw
- ++ABartholomew

[illegible]
- Ryan Lantz
- Kelly Clayton
- Jim Drake
- Paul Elkmann
- Steve Garchow
- Laura Hurley
- Brian Larson
- Tom McKernon
- Mike Murphy
- Tom Stetka
- Brian Tindell
- Gabriel Apger

[illegible]
- Bernadette Baca
- Kenneth Brooks
- James Buchanan
- Lou Carson
- Martin Frato
- Gilbert Guerra
- David Holman
- James Larsen
- Larry Ricketson
- Donald Stearns
- Randy Patterson
- Chris Graves

[illegible]
- David Proulx
- John Mateychick
- Hasan Abuseini
- Paula Goldberg
- Greg Pick
- Steven Alferink
- Neil O'Keefe
- Brian Correll
- Eric Ruesch
- *Ray Mullikin
- ++Avi Wolfson

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- Mary Jane Spivey,Sec'y

Chuck Paulk – Team Leader, Technical Support Staff
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- Loretta Williams

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- Mahdi Hayes, NSPDP
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- **Comanche Peak**: Don Allen, SRI; Alfred Sanchez, RI; Sue Sanner, SS
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- Frank Brush, SPE
- Joseph Bashore, PE
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- **Callaway**: Michael Peck, SRI; David Dumbacher, RI; Dawn Yancey, SS
- **Wolf Creek**: Steve Cochrum, SRI; Christopher Long, RI; Vacant, RI; Shirley Allen, SS

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- Wayne Walker, SPE
- Douglas Bollock, PE
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- **Cooper**: Nick Taylor, SRI; Vacant, RI; Sue Farmer, SS
- **River Bend**: Vacant,SRI; Michael Miller, RI; Lisa Day, SS

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- Rebecca Nease, SPE
- Michael Chambers, PE 3)
- *William Johnson
- ++Tony Mendoza, Jr.
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Jeff Clark – Chief, Branch E
- George Replogle, SPE
- John Hanna, SPE 4)
- John Kirkland, PE
- Jeremy Groom, NSPDP
- **Arkansas**: Rick Deese, SRI; Jeff Josey, RI; Cale Young, RI; Vicki High, SS
- **Fort Calhoun**: John Hanna, SRI; Leonard Willoughby,RI; Bernadette Madison, SS
- **San Onofre**: Clyde Osterholtz, SRI; Mark Sitek, RI; Vacant, SS
- **Waterford**: Grant Larkin, SRI 2); Dean Overland, RI; Ann Youngs, SS

Myra L. Hays, Director – Division of Resource Management & Administration

- Denise Freeman, Sec'y

Bart J. Ehlinsky – Regional Personnel Officer, Human Resources Staff
- Joseph Lopez
- Sandy Lindsay
- Mary Scott
- Jennie Morrison

Lara Uselding-Blackshear – Chief, Financial Resource Management Branch
- Kathy Gardin
- Marisa Herrera
- Carol Hill
- Laura Martinez
- Ann Mattila
- June Morris

Contractor
- Allen Mather
- Mark DeLaVega
- James Franklin

John L. Pellet – Chief, Information Resource Management
- David Crockett
- Jill De La Garza
- Trevor Fleischmann
- George Mueller
- Stacey Munroe
- Janet Staub
- Regina Flores
- Phil Longdo
- Debby Bacon

Revised 06/04/2007
* Acting or Temporary
+NLT 7/07/2007
#in HQs until 8/18/07
++Summer EA (NLT 8/24/07)
1) through 7/28/07
2) SRI @ RBS (8/2007)
3) RI @ CNS (date: TBD)
4) through 8/18/2007

UNITED STATES
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611 Ryan Plaza Drive - Suite 400
Arlington, Texas 76011-4005

Bruce S. Mallett, Ph.D.
Regional Administrator
U. S. Nuclear Regulatory Commission
Region IV

Dr. Bruce S. Mallett has been the Regional Administrator for the Region IV Office of the Nuclear Regulatory Commission (NRC) since September 2003. Dr. Mallett is a graduate of Purdue University with a Ph.D. in Health Physics. He has both a Masters Degree in biochemistry and a Bachelor of Science degree in microbiology from Wright State University.

Prior to joining the NRC, Dr. Mallett was an instructor at Purdue University in the Biology Department. He also served as the radiation safety officer and medical physicist at Grandview Hospital in Dayton, Ohio.

Dr. Mallett joined the NRC in 1980 as a materials licensing reviewer in the Office of Nuclear Material Safety and Safeguards. Since that time, he has held progressively more responsible positions in Region III and Region II, including materials licensing reviewer and inspector in Region III; Chief, Nuclear Materials Licensing Section in Region III; and Chief, Nuclear Materials Safety and Safeguards Branch in Region III. In 1990, he was appointed to the Senior Executive Service (SES) and served as the Deputy Director and Director, Division of Radiation Safety and Safeguards (renamed the Division of Nuclear Materials Safety) as well as the Director, Division of Reactor Safety in Region II. He became the Deputy Regional Administrator in January 2000.

During his career, Dr. Mallett participated in several major Agency tasks, including the Business Process Reengineering Project in the Office of Nuclear Materials Safety and Safeguards, the first annual revision of the Agency's Strategic Plan and the development of the risk-informed, reactor oversight program.

JULY 2005

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611 Ryan Plaza Drive - Suite 400
Arlington, Texas 76011-4005

Thomas P. Gwynn
Deputy Regional Administrator

U.S. Nuclear Regulatory Commission
Region IV

Thomas P. Gwynn is the Deputy to the Regional Administrator for Region IV of the Nuclear Regulatory Commission. In this role, he is responsible to assist the Regional Administrator in the efficient and effective execution of NRC's regulatory responsibilities in the 22 state region.

Mr. Gwynn is a native of Indiana. He served as a submarine reactor operator in the Navy nuclear propulsion program from 1969 to 1975. After leaving military service, he entered Purdue University, where he received a bachelor of science degree in nuclear engineering in 1979. He joined the NRC in 1980 after working at Westinghouse Electric Company's Bettis Atomic Power Laboratory.

At the outset of his NRC career, Mr. Gwynn was a resident and senior resident inspector in Region III. From 1987 to 1989, he served as technical assistant to former NRC Chairman Lando Zech in NRC headquarters.

Mr. Gwynn first came to Region IV in 1989, when he was appointed Deputy Director, Division of Reactor Projects. He subsequently served as the Director, Division of Reactor Safety from February 1994-March 1997, and as the Director, Division of Reactor Projects from March 1997 to January 1999. He has been the Deputy to the Regional Administrator since January 1999.

Mr. Gwynn resides in Duncanville, Texas, with his wife Emily, son Michael, and daughter Carmen.

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June 2005

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611 Ryan Plaza Drive - Suite 400
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ARTHUR T. HOWELL III
Director
Division of Reactor Projects

Arthur T. Howell III is the Director, Division of Reactor Projects for Region IV of the Nuclear Regulatory Commission. This division provides regulatory oversight of regional reactor sites through implementation of the reactor oversight program.

Mr. Howell was born in Japan and raised in California. He was graduated from the United States Naval Academy where he earned a bachelor of science degree in 1979. After graduation, he served in the United States Navy nuclear power program as a submarine officer, and then worked briefly for Pacific Bell and the Impell Corporation. He also earned a master of arts degree in National Security Studies from Georgetown University in 1990.

He joined the NRC in 1985 in the Office of Inspection and Enforcement as an inspector. After an NRC reorganization in 1987, he became a member of the Diagnostic Evaluation and Incident Investigation Branch where he served as the maintenance team leader for several NRC Diagnostic Evaluations. In 1988, he became a member of the technical staff of NRC Region IV, where he has held positions of increasing responsibility. Mr. Howell was selected for the Senior Executive Service in 1996 when he was named the deputy director, Division of Reactor Projects in Region IV. He was subsequently selected as the director, Division of Reactor Safety in March 1997. Following the completion of a temporary assignment as the NRC's team leader for the Davis-Besse Reactor Vessel head Degradation Lessons-Learned Task Force, Mr. Howell was named as the Director of the Division of Reactor Projects in NRC Region IV, effective November 2002.

JANUARY 2004

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611 Ryan Plaza Drive - Suite 400
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Dwight D. Chamberlain
Director, Division of Reactor Safety

Dwight D. Chamberlain is currently Director, Division of Reactor Safety for Region IV of the Nuclear Regulatory Commission. This division provides regulatory oversight of regional reactor sites through implementation of the region-based inspection program.

Mr. Chamberlain is originally from Arkansas and a graduate of the University of Arkansas where he earned a bachelor of science degree in electrical engineering in 1971. Mr. Chamberlain was a registered professional engineer in the States of Arkansas and Texas.

Prior to joining the NRC, Mr. Chamberlain spent about 10 years working in power plant operations, testing, and startup. Mr. Chamberlain joined the NRC in 1980 as a reactor engineer in the vendor branch in Region IV where he was the lead inspector for several major architect engineering firms and nuclear steam system suppliers. In 1983, Mr. Chamberlain was assigned as senior resident inspector at a boiling water reactor facility where he served until 1988. Mr. Chamberlain was promoted to section chief in 1988 and he received the meritorious service award for management excellence in 1988.

In 1991, Mr. Chamberlain was assigned as Deputy Director of the Division of Reactor Safety. Beginning in 1991, Mr. Chamberlain served as deputy director of all three technical divisions in Region IV including his assignments as Deputy Director of the Division of Nuclear Material Safety and acting Deputy Director of the Division of Reactor Projects. Mr. Chamberlain was selected for the Senior Executive Service Candidate Development Program in September 1993 and completed the program in 1994.

Mr. Chamberlain entered the Senior Executive Service on May 11, 1997, with his selection as Deputy Director, Division of Reactor Safety. In February of 1999, Mr. Chamberlain was selected as Director of the Division of Nuclear Materials Safety. This division provided regulatory oversight including licensing and inspection of nuclear materials users in Region IV. The Division also had inspection responsibility for fuel cycle, uranium recovery, reactor and non-reactor decommissioning, and spent fuel activities.

Mr. Chamberlain was assigned to his current position as the Director of the Division of Reactor Safety in November of 2002. Mr. Chamberlain also served as Acting Deputy Regional Administrator in Region IV for approximately four months in FY2003.

January 2004

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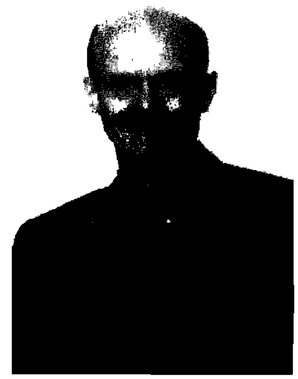

Leonard D. Wert, Jr.
Director, Division of Nuclear Materials Safety
U.S. Nuclear Regulatory Commission
Region IV
Arlington, Texas 76011

Mr. Wert began serving in his present position in May 2005. Prior to his current assignment, he was the Deputy Director, Division of Reactor Projects in the NRC's Region II office in Atlanta since August, 2003. He joined the Nuclear Regulatory Commission in 1987. Mr. Wert has held positions of increasing responsibility in the NRC Region II office including: Resident Inspector, Oconee Nuclear Station; Senior Resident Inspector, Hatch Nuclear Plant; Senior Resident Inspector, Browns Ferry Nuclear Plant; Branch Chief, Division of Reactor Projects, and Branch Chief, Fuel Facility Branch. He graduated from the NRC Senior Executive Service Candidate Development Program in January 2004.

Prior to joining the NRC, Mr. Wert served for seven years on active duty as a submarine officer and an instructor in the Navy's Nuclear Power Program. He received a B.S. degree in Nuclear Engineering from the University of Florida.

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MYRA HAYS
Director, Division of Resource
Management and Administration

Myra Hays is the Director of the Resource and Administration Division for Region IV of the Nuclear Regulatory Commission. This division provides budgetary, human resource and information technology services to all divisions and employees working in Region IV.

Ms. Hays was born in Oklahoma and raised in Texas. She earned her Bachelor of Science degree in business management with an emphasis in accounting in August of 1981 from the University of Maryland. One year later, August of 1982, she earned her Masters Degree in management from Troy State University.

Myra joined the NRC in September of 2005 as the DRMA Director. She came to the NRC from the U.S. Coast Guard Finance Center in Chesapeake, VA. where she was the Director of Accounting Operations supervising over 275 personnel in all aspects of financial and accounting functions. Prior to employment with the U.S. Coast Guard, Ms. Hays served for 11 years as the Director of Resource Management for the Dept. of Homeland Security Immigration and Naturalization Service, a job that mirrors the same functions as her current role as DRMA Director for the NRC. During her 11 years with the INS, she had the opportunity to head the INS Finance Center in all aspects of billing/payment processing, financial statements, Treasury reporting, TDY and PCS payment processing etc. Prior to the INS, his Hays worked for the Army Corps of Engineers in Dallas, Texas as an accountant, the Dept. of the Army in St. Louis, Missouri as a systems accountant, the U.S. Air Force Academy in Colorado Springs, Colorado as Deputy Finance Officer, the Dept. of the Air Force Finance Center in Denver, Colorado (supervisory accountant), the Dept. of Housing and Urban Development in Denver, Colorado (supervisory accountant) and the U.S. Air Force Morale, Welfare and Recreation (MWR) organization in Upper Heyford, England (supervisory accountant). Having such a varied background with many other agencies has allowed Myra the opportunity to bring to the NRC expertise in every aspect of the DRMA division responsibilities to include budget, contracting, payroll, personnel, IT, auditing and leadership in general. Myra has been an active member of the American Society of Military Comptrollers for most of her 25 years of federal service.

Myra states: "I am proud to be an employee of such a fine organization and became such in the year that the NRC was recognized as one of the best places to work in the federal government."

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Antone (Tony) Vegel
Deputy Director
Division of Reactor Projects

Tony Vegel has been selected as the Deputy Director of the Division of Reactor Projects in Region IV. He is currently the Systems Engineering Branch chief in the Division of Reactor Safety in RIII. Tony is a graduate of the 2002 SES Candidate Development Program.

He has formerly served as a Branch Chief in the Division of Reactor Projects in Region III. While in that position he led the 95003 supplemental inspection at Point Beach. Prior to that he led the branch in implementing the Manual Chapter 0350 process at the D.C. Cook plant providing oversight of the extended shutdown and restart. In 2001, Mr. Vegel was also a team member on the IAEA International Regulatory Review Team mission to Lithuania.

Prior to his selection as a Branch Chief in 1998, Mr. Vegel had extensive field experience as an inspector at both boiling water reactor and pressurized water reactor nuclear power generation facilities. Mr. Vegel was a Senior Resident Inspector at the Zion Nuclear Power Station from 1997 to 1998, and the Senior Resident Inspector at the Fermi Nuclear Power Plant from 1994 to 1997. In 1997 Mr. Vegel received the NRC Meritorious Service Award for Senior Resident Inspector Excellence. Prior to being a Senior Resident Inspector, he was the Resident Inspector at the Perry Nuclear Power plant from 1991 through 1994. Mr. Vegel started his NRC career as a Reactor Engineer in the Division of Reactor Projects at the Region I office in 1989.

Prior to joining the NRC, Mr. Vegel was an officer in the U. S. Navy Submarine force. Mr. Vegel started his Naval career as an enlisted sailor, was subsequently selected to the U. S. Naval Academy, where he graduated in 1983 with a Bachelor of Science degree.

AUGUST 2004

UNITED STATES
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611 Ryan Plaza Drive - Suite 400
Arlington, Texas 76011-4005

Roy J. Caniano, Deputy Director
Division of Reactor Safety
U. S. Nuclear Regulatory Commission
Region IV

Mr. Caniano began serving in his current position in October, 2005. He is originally from Illinois and attended the University of Illinois and Lewis University attaining degrees in Nuclear Medicine and Management.

Mr. Caniano joined the NRC in 1982 as a Materials Radiation Specialist in Region III. Since then he has held various positions of increasing responsibilities including serving as a Senior Technical Assistant to the Director Division Radiation Safety and Safeguards and the Regional Administrator; Chief, Nuclear Materials Safety Inspection and Licensing Sections; Chief, Nuclear Materials Inspection and Licensing Branch; Chief, Materials Decommissioning Branch; Chief, Reactor Plant Support Branch; Deputy Director, Division of Nuclear Materials; and Deputy Director, Division of Reactor Safety. Mr. Caniano is a graduate of the OPM sponsored Executive Potential Program and entered the Senior Executive Service in 1996 when he was selected for the position of Deputy Director, Division of Nuclear Materials Safety.

November 2005

Slide 1

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UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Region IV Overview and Challenges

Bruce S. Mallett, Ph.D., Regional Administrator
T. P. (Pat) Gwynn, Deputy Regional Administrator

Slide 2

U.S.NRC

Region IV Overview

- Introductions
- Generally Similar To Other NRC Regions
- Geographically Large
- Talented, Experienced Staff
- 22 Reactors At 14 Sites in 10 States
- Diverse Mix of Reactor Vendors

Slide 3

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Challenges in Reactor Oversight

- Recruitment/retention of skills inventory
- Maintaining resident inspector pipeline
- Knowledge Management
  - -Knowledge Transfer
  - -Fundamentals
  - -Remembering lessons learned
  - -Event history

Slide 4

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Protecting People and the Environment

Challenges in Reactor Oversight

- Cross-cutting "issue" or "aspect"
- Alignment on "how much SDP evaluation"
- Effective outreach/external communication
- "Turning over every rock" – trust but verify

Slide 1

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Knowledge Management Overview

Joseph Lopez, Human Resources Management Specialist
Roy Caniano, Deputy Director, Division of Reactor Safety

Slide 2

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Protecting People and the Environment

Region IV Knowledge Management Overview

- Communication with staff
- Implementation of KM activities and strategies
- Staff development and production of future leaders

Slide 3

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Protecting People and the Environment

Communication with Staff

- ➤Knowledge Management Plan
- ➤Human Capital Management Plan
- ➤PBPM
- ➤Resource Planning Meetings
- ➤Current Events
- ➤Orientation

Slide 4

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Implementation of KM Activities and Strategies

- Best Practices - Recruitment & Retention
- NSPDP Mentor/Advisor
- Bi-weekly Reviews of Operational Experience
- Questionnaire – Hiring Process
- Knowledge Management Corner
- Management Info Icon
- Post-Certification Interviews

Slide 5

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Protecting People and the Environment

Staff Development and Production of Future Leaders

- Management Library
- Double Encumbering
- Rotational Assignments
- Reverse Mentoring
- Leading Examples Program
- Auditing and Introducing Training Courses
- SESCDP and LPP
- Knowledge Management Seminars

Slide 6

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Protecting People and the Environment

REGION IV KNOWLEDGE MANAGEMENT SESSIONS

- Initiated Knowledge Management Sessions mid 2006
- Presenters include senior staff and management; NSPDP participants; summer hires; rehired annuitants

Slide 7

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REGION IV KNOWLEDGE MANAGEMENT SESSIONS

- Topics included significant agency responses (AIT at Point Beach; IIT at TMI); fire protection issues; interpreting electrical diagrams; ASME code interpretations; Chernobyl event. Presentations limited to 60-90 minutes.
- Presentations open to all staff including resident inspectors

Slide 8

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REGION IV KNOWLEDGE MANAGEMENT SESSIONS

- Presentation material posted on RIV web page (KM Corner)
- Monday KM sessions sponsored by SRAs
- Effectiveness assessment recently done
- Moving forward initiatives include hosting non-technical sessions and video taping

Slide 1

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Protecting People and the Environment

Reactor Oversight Process
Case Study #1

John David Hanna, Senior Resident Inspector, FCS

Slide 2

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Fort Calhoun Station "Mega" Outage

- Topics for this Presentation
- Scope of the Outage
- Substantiative Cross Cutting Issue
- Movement to Column 3 of the ROP Action Matrix
- Questions

Slide 3

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Protecting People and the Environment

Fort Calhoun ISFSI Installation

3

Slide 4

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Transportation of Major Replacement Components

4

Slide 5

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Protecting People and the Environment

Brock Hammering Of Containment Concrete Up To the Liner Plate

5

Slide 6

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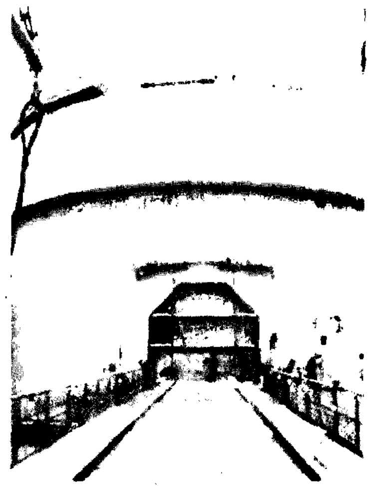
Overall View of the Containment Opening



6

Slide 7

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Inside View of Containment

7

Slide 8

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Fort Calhoun Station Substantiative Cross Cutting Issue

- "Where" did the findings/violations occur?
- Brief description of the individual issues
- Regional assessment of this pattern/trend
- Commonalities to these issues
- Results of the substantiative cross cutting issue

Slide 9

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Containment Spray Valve Inoperable

9

Slide 10

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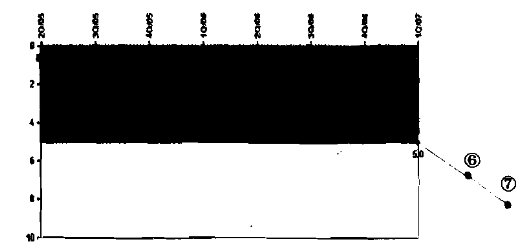
Safety System Functional Failure Performance Indicator



10

Slide 11

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Reactor Oversight Program Action

- Inputs
- Assessment of the Licensee's Performance
- Actions Taken (or that will be taken) by the Agency
- Actions Taken by the Licensee

11

Slide 12

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Protecting People and the Environment

Questions?

12

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ROP Best Practices

Michael Hay, RIV DRP Branch Chief

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- STARS
- Resident Inspector Counterpart Meetings
- Inspector Newsletter
- Daily Morning Meeting
- Operating Experience

2

Slide 1

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Protecting People and the Environment

ROP Case Study #2

Wayne C. Walker, Senior Project Engineer

Slide 2

Use of the ROP to Increase Oversight

- 95001, 95002, and 95003 inspections completed
- CNS entered multiple/repetitive degraded cornerstone due to EP
- CAL confirmed NPPD commitments
- Closed EP White Findings
- Action matrix deviation requested and approved

Slide 3

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Successful Use of the ROP

- Closed CAL and Action Matrix Deviation Memorandum
  - Conducted team inspections and held public meetings

- NPPD returned to Licensee Response Column of Action Matrix

3

Slide 4

U.S.NRC

Conclusions

- ➢ What Have We Learned?
- ➢ What Worked Well and What Did Not Work Well?

4

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Protecting People and the Environment

ROP Case Study #3

Greg Warnick, Senior Resident Inspector

Slide 2

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Contents

- ➢Historical performance
- ➢Current performance
- ➢Value added through the ROP

2

Slide 3

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Historical Performance

- "10 Years of Excellence"
- 2003 - Licensee Response Column
  - High Number of Allegations (>30)
- 2004 - Licensee Response Column
  - Loss of offsite power and three unit trip event (AIT)
  - Containment sump suction piping found void of water
  - Substantive crosscutting issues in human performance and problem identification and resolution
  - Met with licensee to discuss high number of allegations and licensee assessment of SCWE in the I&C department

3

Slide 4

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Historical Performance (Cont'd)

- 2005 - Degraded Cornerstone Column
  - Severity Level III 50.59 violation and Yellow Finding associated with voiding in containment sump suction piping
  - Severity Level III violation for decrease in effectiveness of Emergency Plan
  - Meetings with licensee on improvement plans, corrective actions, and work climate survey results
  - 95002 Supplemental Inspection closed Severity Level III violation; however, the Yellow Finding remained open because not all corrective actions were fully effective
  - High number of inspection findings continued to be identified (>30), indicating a lack of progress in addressing substantive crosscutting issues
- Received an INPO 3 Performance Rating

Slide 5

U.S.NRC Historical Performance (Cont'd)

- 2006 - Degraded Cornerstone Column
  - Licensee presents Performance Improvement Plan and status of implementation during three public meetings
  - Conducted special inspections of essential cooling water heat exchanger fouling and failures of the Unit 3, Train A emergency diesel generator
  - Followup 95002 Supplemental Inspection leaves Yellow Finding open because of ineffective corrective actions in questioning attitude, technical rigor, and operability determinations. Effectiveness measures did not include all relevant data.
  - High number of inspection findings (>40) with continued substantive crosscutting issues in human performance and problem identification and resolution

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Current Performance

- Repetitive Degraded Cornerstone Column
  - The 2004 Yellow Finding remains open due to some corrective actions that were not fully effective
  - Recent White Finding on Unit 3 emergency diesel generator places Palo Verde in the Repetitive Degraded Cornerstone Column of the Action Matrix
  - Units 1 and 2 remain in the Degraded Cornerstone Column
  - The two substantive crosscutting issues in human performance and problem identification and resolution have remained open since the 2004 Annual Assessment letter

Slide 7

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Value Added Through ROP

- Key observations and findings
  - Crosscutting aspects
  - Poor safety culture
  - Failure to perform a thorough review of issues
  - Accepting incomplete answers and actions
  - Failure to question the impact of actions
  - Ineffective communication between Operations and Engineering
  - Operability determinations not thorough
- Licensee "Push Back"
  - Stages of denial to eventual acceptance

Slide 1

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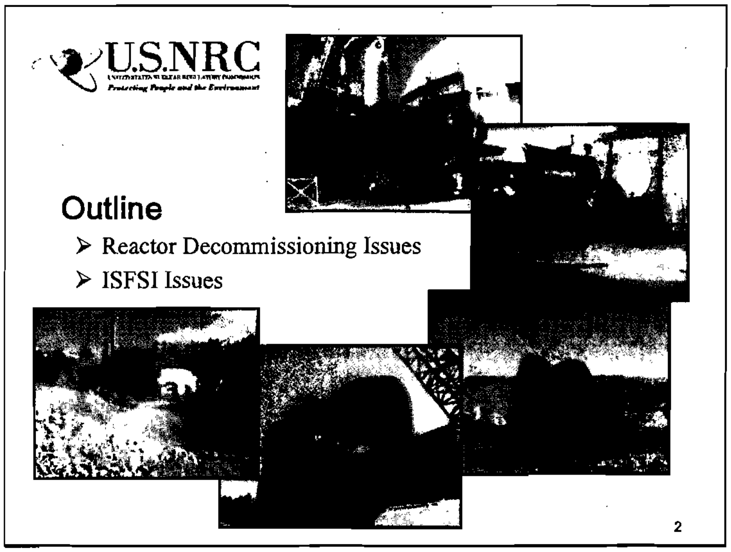
Protecting People and the Environment

Recent Technical Challenges in the Reactor Decommissioning and Independent Spent Fuel Storage Installation (ISFSI) Inspection Areas

D. Blair Spitzberg, Ph. D., RIV FCDB Branch Chief

Slide 2


U.S.NRC
Protecting People and the Environment
Outline
➢ Reactor Decommissioning Issues
➢ ISFSI Issues
2

Slide 3

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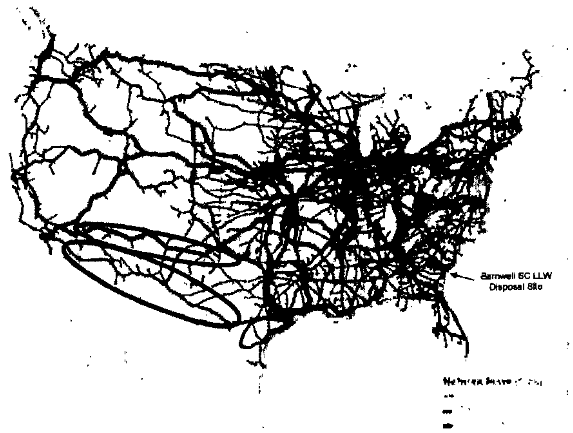
Protecting People and the Environment

Decommissioning San Onofre Unit 1

- OL: 1967-1992
- Dismantlement in progress
- All fuel in ISFSI
- Tritium in groundwater beneath the site
- Disposal of grouted RPV remains unresolved

Slide 4

SONGS 1 RPV Disposal Option 1 – Transport by rail to Barnwell, SC



Slide 5

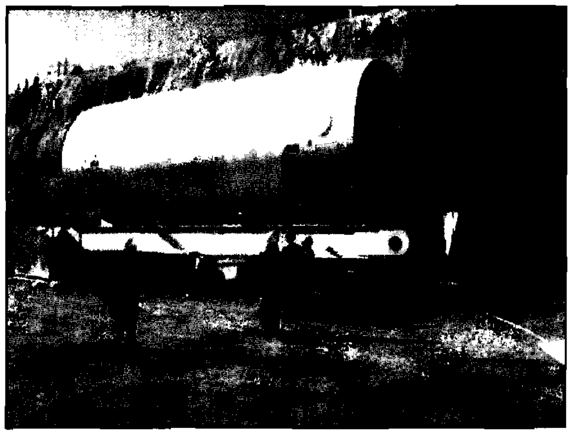
Disposal Option 2 – Transport by (Unsinkable) Sea Barge through Panama Canal to Barnwell, SC

Slide 6

Disposal Option 3 – Transport by (Unsinkable) Sea Barge Around Cape Horn South America to Barnwell, SC

Slide 7

Disposal Option Selected – Leave it onsite until other options develop or until the entire site is decommissioned



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Other Recent Issue with Permanently Shutdown Reactor

- Humboldt Bay missing fuel fragments
  - Three small rod segments cut in 1968
  - Intended shipment for examination never took place
  - Records could not account for segments
  - Extensive search/investigation failed to locate segments
  - Most probable scenario: After SFP cleanup effort, shipped by mistake with LLW to burial site
  - NRC enforcement - $96K Civil Penalty

8

Slide 9

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United States Nuclear Regulatory Commission

Protecting People and the Environment

Challenging RIV Inspection Issues in ISFSI Arena

- Canister Handling Crane Issues
- Use of Lightweight Transfer Cask
- ISFSI Construction with Ongoing Legal Issues

Slide 10

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Protecting People and the Environment

Cask Handling Crane Issues

- Seismic analysis of crane support
- Irregularities with last 125% load test (1980)
- Lost documentation of crane weld inspections
- Crane maintenance issues
- Single failure proof crane issues
  - Hoist gears dry and galled
  - Inoperable systems - wire rope equalizing system, bridge and trolley limit switches, crane load hang-up protection
  - gearbox lubricant issues
  - Inadequate cold proof test

Slide 11

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Protecting People and the Environment

Use of Lightweight Transfer Cask

- Proposed lightweight transfer cask due to 75-ton crane capacity
- Removal of 25-tons of shielding
- Use licensee/vendor approval process (10 CFR 72.48)
- Up to 53 Rem/hr for DB fuel
- Use of remote crane operation - cameras and laser sights
- Canister draindown earlier than specified in FSAR potentially affecting vacuum drying TS time limit (cladding protection)
- NRC determined changes could not be self-approved under 10 CFR 72.48
- Licensee subsequently sought and received NRC exemption to load 4 casks with old cold fuel
- RIS 2006-22: "Lessons Learned From Recent 10 CFR Part 72 Dry Cask Storage Campaign" issued 11/15/2006

Slide 12

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United States Nuclear Regulatory Commission
Protecting People and the Environment

Inspection of Diablo Canyon ISFSI

- Notwithstanding recent legal challenges regarding consideration of terrorist attacks in conducting the Diablo Canyon ISFSI environmental reviews, Region IV continues to conduct time sensitive inspections in construction and pre-operational areas
- Inspections to date:
  - Fabrication of ITS Transporter,
  - Construction of transport roadway, ISFSI pads (7.5 feet thick), Cask Transfer Facility
  - Installation of grouted rock anchors for transporter seismic tie down

12

Slide 13

Slide 1

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Protecting People and the Environment

Safety Culture

Roy Caniano, Deputy Director, Division of Reactor Safety
Linda Smith, Branch Chief EB 2

Slide 2

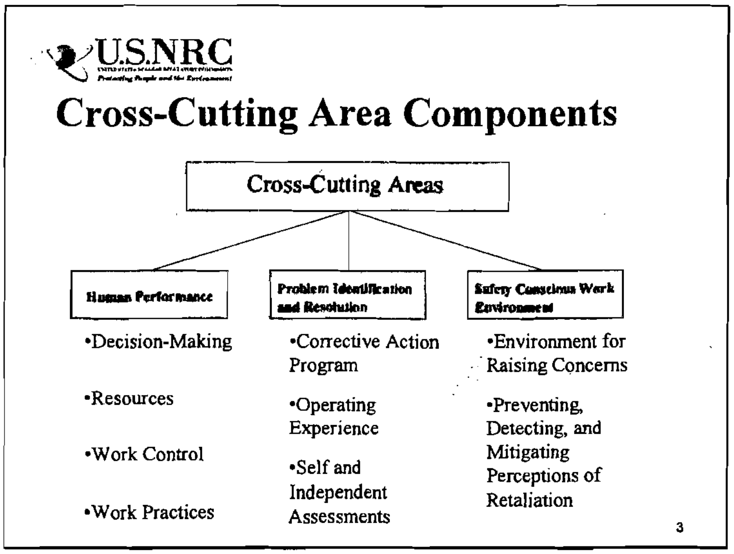
U.S.NRC

Protecting People and the Environment

Safety Culture Components

- Corrective Action Program
- Operating Experience
- Self and Independent Assessments
- Decision Making
- Resources
- Work Practices
- Work Control
- Preventing, Detecting, and Mitigating Perceptions of Retaliation
- Environment for Raising Concerns

Slide 3


U.S.NRC
Cross-Cutting Area Components
Cross-Cutting Areas
Human Performance
Problem Identification and Resolution
Safety Conscious Work Environment
•Decision-Making
•Resources
•Work Control
•Work Practices
•Corrective Action Program
•Operating Experience
•Self and Independent Assessments
•Environment for Raising Concerns
•Preventing, Detecting, and Mitigating Perceptions of Retaliation
3

Slide 4

U.S.NRC
Protecting People and the Environment

Cross-Cutting Aspect

- Performance characteristics that comprise a cross-cutting area component.
- Example
- Safety Conscious Work Environment Cross-Cutting Area
  - Environment for Raising Concerns Cross-Cutting Component
    - S.1(a)-Behaviors and interactions encourage free flow of information related to raising nuclear safety issues, differing professional opinions, and identifying issues in the CAP and through self assessments.

      Cross-Cutting Aspect

Slide 5

Cross-Cutting Analysis

- Cross-Cutting Aspects
- Substantive Cross-Cutting Issues

Slide 6

U.S.NRC

Safety Culture Assessment

- Recurring Substantive Cross-Cutting Issues
- Degraded Cornerstone
- Multiple/Repetitive Degraded Cornerstone

6

Slide 7

U.S.NRC

Program Oversight Challenges

- Complex terminology
- Calibration between regions
- Addressing Lesson's Learned

7

Slide 8

U.S.NRC

Protecting People and the Environment

Stakeholder Training

- NRC Inspector
  - Counterpart Meetings Spring 2006, Fall 2006, Spring 2007
  - NRC Web-based training
  - Management oversight of inspection findings
  - Root Cause Evaluation Training
- Security Community - Fall 2006
- Regional Utility Groups (all regions)

8

Slide 9

U.S.NRC

NRC ROP/Safety Culture Program Assessment

- ROP Annual Self Assessment Report
- 18 month ROP SC Self Assessment
- Routine Procedure Review and Upgrade
- MC 0612 /Working Group – performance deficiencies/CCA audit

Slide 10

U.S.NRC

NRC ROP/Safety Culture Program Assessment

- 95003 Lessons Learned Report
- Cross-Regional Participation MOC/EOC
- NRC Wide Cross-Cutting Issue review – Roy Caniano

Slide 11

U.S.NRC

CROSS CUTTING TASK GROUP

- PURPOSE IS TO IDENTIFY DIFFERENCES AND/OR SIMILARITIES AMONG THE REGIONS
- MEMBERS INCLUDE REPRESENTATIVES FROM EACH REGIONAL OFFICE AS WELL AS NRR AND THE OFFICE OF ENFORCEMENT
- COMPLIMENTING ONGOING PI&R AND 0612 REVIEWS

Slide 12

U.S.NRC

Protecting People and the Environment

CROSS CUTTING TASK GROUP

- REVIEWING STATISTICS (INDUSTRY AND AGENCY)
- PARTICIPATING IN MID CYCLE REVIEWS AND INSPECTION DEBRIEFS
- REVIEWING APPROXIMATELY 60 INSPECTION REPORTS
- INTERVIEWING INSPECTORS AND SUPERVISORS
- COMPLETION BY END OF CALENDAR YEAR

Slide 1

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Component Design Basis Inspections

George Replogle, Senior Project Engineer

Slide 2

U.S.NRC

Component Design Basis Inspections

- Latest Version of Engineering Team Inspection
- Trial Inspections in 2005
- Jan 1, 2006 started CDBIs
- Biennial Inspection
- Large Team (6 members), including
  - Two A&E Contractors
  - One Operations examiner

Slide 3

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

On site time

- Team spends 3 weeks on site and two weeks preparing
- Team Leader and Senior Reactor Analyst spend an addition prep week on-site (bag man trip) to obtain inspection materials, including PRA data.

Slide 4

U.S.NRC

Risk Informed Scope

- Approximately 20 risk important/low margin components
- 5 risk important operating experience issues
- 5 risk important operator actions

Slide 5

U.S.NRC

Scope

- Team spends about 1/3 of the 5 week inspection and planning time just to identify the scope. Input from:
  - PRA
  - Design Basis Documents
  - FSAR
  - Technical Specifications
  - Misc.

Slide 6

U.S.NRC

Findings

Nationwide

- Green – 136 findings and violations
- White – 1 - Vortexing Issue at Clinton and (Region III)

Region IV

- Green – 24 findings and violations

U.S.NRC

Find Latent Design Issues

- Not everything that occurred at TMI was a "risk significant" problem.

Slide 10

U.S.NRC

Strengths

- Looking deeper into design
- Identifying design problems in place since construction
- Evaluate licensee maintenance of design

Slide 11

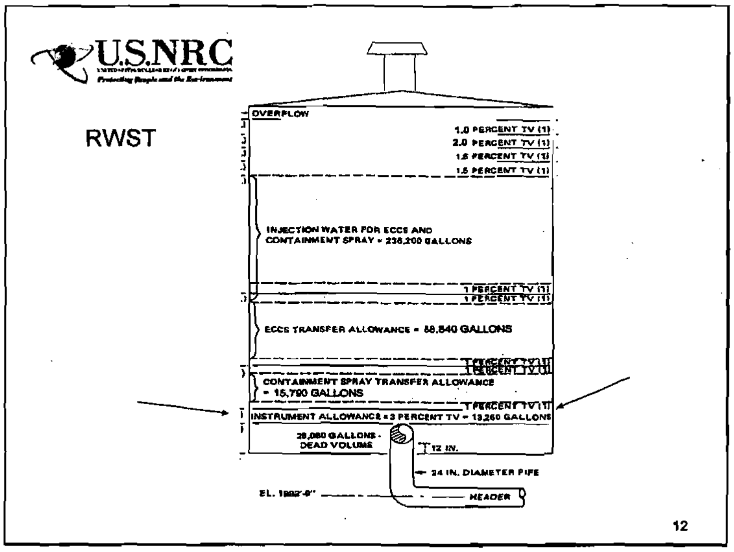
U.S.NRC

Challenges

- Inconsistencies
  - AE Contractor Quality
  - Inspector Skill, Experience and Drive
  - Licensee Support
  - Team Leader Skills
- Significant Resource Demands

11

Slide 12


U.S.NRC
RWST
OVERFLOW
1.0 PERCENT TV (1)
2.0 PERCENT TV (1)
1.5 PERCENT TV (1)
INJECTION WATER FOR ECCS AND
CONTAINMENT SPRAY = 236,200 GALLONS
1 PERCENT TV (1)
1 PERCENT TV (1)
CONTAINMENT SPRAY TRANSFER ALLOWANCE
= 15,790 GALLONS
1 PERCENT TV (1)
INSTRUMENT ALLOWANCE = 3 PERCENT TV = 13,260 GALLONS
DEAD VOLUME
12 IN.
24 IN. DIAMETER PIPE
HEADER
12

Slide 13

U.S.NRC
Protecting People and the Environment

13

Résumés of SONGS Resident Inspectors

Clyde Osterholtz, Senior Resident Inspector

Mr. Osterholtz has been the Senior Resident Inspector at San Onofre since May 2001. Prior to joining the NRC, Mr. Osterholtz served in the United States Navy Submarine Service as an electronics technician and reactor operator from 1980 to 1986. Mr. Osterholtz graduated from The Ohio State University in 1990 with a Bachelor of Science degree in Engineering Physics/Nuclear Engineering, and joined the NRC in September 1990 as a licensing examiner in the Division of Reactor Safety in Region III. In 1996, he was selected as Resident Inspector at Ginna Nuclear Generating Station in the Division of Reactor Projects in Region I.

Mr. Osterholtz transferred to the resident inspector position at the Fort Calhoun Generating Station in the Division of Reactor Projects in Region IV in 2000, and was selected for the Senior Resident Inspector position at San Onofre in October of that same year.

Mr. Osterholtz has led or participated in numerous team inspections throughout his career, including leading a special inspection in response to a breaker fire at San Onofre in February 2001.

Mark Sitek, Resident Inspector

Mark Sitek is the Resident Inspector at San Onofre Nuclear Generating Station. Mr. Sitek joined the agency through the NRC's Graduate Fellowship Program in June 1996. He entered the program following completion of his Bachelor of Science in Nuclear Engineering from Rensselaer Polytechnic Institute in 1996. Mr. Sitek began his NRC career in the then Office of Nuclear Materials Safety and Safeguards (NMSS), Division of Industrial and Medical Nuclear Safety as a general engineer.

In August 1997, Mr. Sitek returned to school as part of the fellowship program where he earned a Master of Science in Nuclear Engineering from the Massachusetts Institute of Technology in September 1999. Following graduate school, he returned to NMSS in February 2000 as a health physicist where he completed a rotational assignment to Region I and qualified as a materials health physics inspector.

Mr. Sitek became the Resident Inspector at San Onofre in May 2002. Since that time, he has completed rotational assignments as Senior Resident Inspector at Grand Gulf Nuclear Station and as Team Leader, Technical Support Staff in Region IV.

Nuclear Organization

- **Dick Rosenblum**
  Senior Vice President
  - Ray Waldo
    Vice President
    Nuclear Generation
  - James Reilly
    Vice President
    Engineering & Technical Services
  - Brian Katz
    Vice President
    Nuclear Oversight & Regulatory Affairs
  - Mike Short
    Manager
    Leading the Way to
    Nuclear Excellence

NUCLEAR GENERATION
AS OF JUNE 30, 2007

Figures are Budget / Actual

RAY WALDO
Vice President,
Nuclear Generation

Total SCE	824	759
Mgmt		321
Operative		501
SCE PT/Temp	1	5
Agency/Contract	172	214

TED VOGT
Special Projects

Kimberly Mendicelli
Executive Assistant

Staffing Pipeline = 5
(not counted)

OSCAR FLORES
Manager,
Chemistry

Total SCE	39	37
Mgmt		20
Operative		22
SCE PT/Temp	0	0
Agency/Contract	0	0

TOM YACKLE
Manager,
Operations

Total SCE	240	230
Mgmt		73
Operative		157
SCE PT/Temp	0	0
Agency/Contract	0	0

ROBERT CORBETT
Manager,
Health Physics

Total SCE	93	84
Mgmt		36
Operative		56
SCE PT/Temp	0	1
Agency/Contract	66	64

TODD ADLER
Manager,
Work Control

Total SCE	30	29
Mgmt		29
Operative		0
SCE PT/Temp	0	0
Agency/Contract	0	1

JOHN HIRSH
Manager,
Maintenance & Construction Services

Total SCE	419	376
Mgmt		160
Operative		266
SCE PT/Temp	1	4
Agency/Contract	106	149

20020
SRO Training
Bates, Al
Bohrisch, Robert
Bosch, Lou
Herschthal, Mark
Murray, Joel

ENGINEERING & TECHNICAL SERVICES
AS OF JUNE 30, 2007

Figures are Budget/Actual

JAMES REILLY
Vice President,
Engineering & Technical Services

Total SCE	559	550
Mgmt		496
Operative		54
SCE PT/Temp	4	9
Agency/Contract	82	113

DAN BREIG
Deputy

Mariane Sanchez
Executive Assistant

HOWARD NEWTON
Manager,
Site Support Services

Total SCE	75	77
Mgmt		50
Operative		27
SCE PT/Temp	2	2
Agency/Contract	48	59

OWEN THOMSEN
Manager,
Nuclear Fuel Management

Total SCE	34	34
Mgmt		34
Operative		0
SCE PT/Temp	2	1
Agency/Contract	0	0

KEN JOHNSON
Manager ,
Design Engineering Organization

Total SCE	165	152
Mgmt		152
Operative		0
SCE PT/Temp	0	4
Agency/Contract	12	16

JOHN FEE
Manager,
Site Emergency Preparedness

Total SCE	49	50
Mgmt		32
Operative		18
SCE PT/Temp	0	0
Agency/Contract	16	14

RICH ST. ONGE
Manager,
Maintenance / System Engineering

Total SCE	136	139
Mgmt		130
Operative		9
SCE PT/Temp	0	2
Agency/Contract	0	0

RON ELSASSER
Manager,
Nuclear Training

Total SCE	69	67
Mgmt		67
Operative		0
SCE PT/Temp	0	0
Agency/Contract	4	3

JORGE MORALES
Manager,
Projects

Total SCE	26	26
Mgmt		26
Operative		0
SCE PT/Temp	0	0
Agency/Contract	1	20

MIKE WHARTON
Manager,
Strategic Issues Project

Total SCE	2	2
Mgmt		2
Operative		0
SCE PT/Temp	0	0
Agency/Contract	1	1

J0000
Cross, Glenn (AC)
Mihalik, Mark

(*) = Loaned from other depts (not counted)
(1) = Loaned to March to Excellence (counted)

NUCLEAR OVERSIGHT & REGULATORY AFFAIRS
AS OF JUNE 30, 2007

Figures are Budget/Actual

* = Security not included in totals

BRIAN KATZ
Vice President,
Nuclear Oversight & Regulatory Affairs

	Budget	Actual
Total SCE	385	375
Mgmt		165
Operative		210
SCE PT/Temp	12	14
Agency/Contract	26	24

MARC GOETTEL
Process Integration
(not counted)

Dawn Farrell
Executive Assistant

JOSE PEREZ
Manager,
Business Planning & Financial Services

	Budget	Actual
Total SCE	40	38
Mgmt		38
Operative		0
SCE PT/Temp	1	1
Agency/Contract	17	15

GARY ZWISSLER
Manager,
Business Administration

	Budget	Actual
Total SCE	158	156
Mgmt		23
Operative		133
SCE PT/Temp	6	7
Agency/Contract	1	0

CAROLINE McANDREWS
Manager,
Nuclear Oversight & Assessment

	Budget	Actual
Total SCE	71	73
Mgmt		73
Operative		0
SCE PT/Temp	0	1
Agency/Contract	2	4

BRIAN CONWAY
Manager,
Staffing Pipeline

	Budget	Actual
Total SCE	87	82
Mgmt		5
Operative		77
SCE PT/Temp	5	5
Agency/Contract	5	5

JOHN TODD
Manager,
Site Security

	Budget	Actual
Total SCE	438	456
Mgmt		
Operational Support		
SCE PT/Temp	0	0
Agency/Contract	1	0

A. E. SCHERER
Manager,
Nuclear Regulatory Affairs

	Budget	Actual
Total SCE	23	19
Mgmt		19
Operative		0
SCE PT/Temp	0	0
Agency/Contract	0	1

WILLIS FRICK
Manager,
Nuclear Safety Concerns

	Budget	Actual
Total SCE	4	5
Mgmt		5
Operative		0
SCE PT/Temp	0	0
Agency/Contract	0	0

V0000
Baker, Randy (V1000)
Giroux, Richard
Green, Laura
Morris, William

Figures are Budget/Actual

LEADING THE WAY TO NUCLEAR EXCELLENCE
AS OF JUNE 30, 2007

MIKE SHORT
Manager,
Leading the Way to Nuclear Excellence

Total SCE	50	41
Mgmt		41
Operative		0
SCE PT/Temp	0	0
Agency/Contract	1	1

Ami Dominguez
(Matrixed)

AOR: 3766 PR # 221 DEPT ID: 03503

- MARTY COOPER (1)
- RON GEORGE (AC)
- MARK PRICE
- STEVE ROOT
- Nuc Regulatory Affairs = 1
  Security = 37

(1) = Loaned from OPS (not counted)

Legend

(AC) = Agency / Contract

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Richard M. Rosenblum

Senior Vice President of Generation and Chief Nuclear Officer
Southern California Edison

Richard M. Rosenblum is senior vice president of Generation and chief nuclear officer for Southern California Edison (SCE), responsible for all power generating facilities, including nuclear and related fuel supplies. He was appointed to his current role in November 2005.

Previously he was senior vice president of the Transmission and Distribution business unit which is responsible for the high-voltage bulk transmission and retail distribution of electricity in SCE's 50,000-square-mile service territory. He assumed that position in February 1998.

Rosenblum began his career at SCE in 1976 as an engineer working at the company's San Onofre Nuclear Generating Station (SONGS). He held various positions in the company's Nuclear Department, including startup manager, station technical manager, nuclear oversight manager, and nuclear regulatory affairs manager. He was elected vice president of Engineering and Technical Services in 1993. In that role he was responsible for engineering construction, safety oversight, and other engineering support activities at SONGS.

In January 1996, he was appointed vice president of the Distribution business unit, which is responsible for providing electric service to SCE's 4.6 million customers.

Rosenblum earned a B.S. and M.S. in nuclear engineering from Rensselaer Polytechnic University.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Raymond W. Waldo

Vice President, Nuclear Generation
Southern California Edison

Raymond Waldo is vice president of Nuclear Generation for Southern California Edison (SCE). Elected to that position on January 1, 2005, he is responsible for the daily operation of the San Onofre Nuclear Generating Station.

Previously, Waldo was the station manager at San Onofre, in charge of operations, maintenance, work control, health physics, chemistry, and training for that facility.

Waldo began his career with SCE in 1980 as a station engineer at San Onofre. He held several engineering and supervisory positions and became the operations manager in 1990 and station manager in 2002.

Before joining SCE, he served in the Peace Corps and was a supervisor at the Livermore Pool Type Reactor at the Lawrence Livermore National Laboratory.

Waldo earned a bachelor's degree in physics from Caltech and a master's degree and doctorate in nuclear engineering from Georgia Tech. He also earned a Senior Reactor Operator license on San Onofre Units 2 and 3 from the Nuclear Regulatory Commission in 1983.

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL Company

James T. Reilly

Vice President, Nuclear Engineering and Technical Services
Southern California Edison

James Reilly, as vice president of Nuclear Engineering and Technical Services, is responsible for engineering, construction, project management, and decommissioning activities at the San Onofre Nuclear Generating Station (SONGS). He was elected vice president in December 2005.

Previously, Reilly was director of Engineering and Technical Services at SONGS, responsible for SONGS engineering organizations, nuclear fuel management, Unit 1 decommissioning services, and site facilities.

Reilly began his Edison career in 1979 as an engineer at San Onofre Unit 1, and held various positions in the company's Nuclear Department, including supevisor and station technical manager. In addition, he was vice president of operations at Edison Technology Solutions; manager of Engineering, Construction and Fuel Services; and manager of Research & Technology Applications.

Before joining Edison, Reilly was a senior engineer at General Atomics and a manufacturing engineer at both General Electric and Swanson Engineering and Manufacturing Company.

Reilly holds a Bachelor of Science degree in mechanical engineering from the University of Redlands and a Master of Science degree in nuclear engineering from the University of California, Los Angeles.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Brian Katz

Vice President, Nuclear Oversight and Regulatory Affairs
Southern California Edison

As vice president of nuclear oversight and regulatory affairs for Southern California Edison, Brian Katz is responsible for the company's nuclear safety and quality programs and interactions with the Nuclear Regulatory Commission.
He manages business planning and budgeting, including nuclear-related California Public Utilities Commission regulatory activities. He is also responsible for co-owner relationships for the San Onofre and Palo Verde nuclear power facilities, as well as management of the security operations.

Prior to his election as vice president in 2005, Katz was manager of the Generation Business Planning and Strategy organization. Having held that position since 1999, he was responsible for managing regulatory, business, and strategic issues, including developing and implementing a business/regulatory restructuring strategy for Edison's nuclear and non-nuclear generation business.

Katz began his Edison career in 1974 as a nuclear systems engineer and held several key management positions within the Nuclear organization.

Before joining Edison, he worked for Metcalf and Eddy Consulting Engineers. Prior to that, he worked for General Electric at the Knolls Atomic Power Laboratory in Schenectady, N.Y. as a reactor fluid systems engineer.

Katz holds a mechanical engineering degree from Pratt Institute, New York, a professional designation in Business Management from UCLA, a certificate in Project Management from UCI, and professional engineering licenses in mechanical and nuclear engineering.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Michael P. Short

Manager, Leading the Way to Nuclear Excellence
San Onofre Nuclear Generating Station

Michael P. Short, as Manager of Leading the Way to Nuclear Excellence, is responsible for the implementation of the San Onofre Nuclear Generating Station (SONGS) Strategic Plan including oversight, facilitation, and qualitative review of the initiates to improve performance at SONGS.

Previously, Short was Manager of Systems Engineering at SONGS, where he was responsible for organization and administration of long term strategies for each system to improve the overall system performance. In this capacity, he also managed special programs including Steam Generators, Flow Accelerated Corrosion, Inconel Nozzles, State of System Report, Operating Experience Reporting, Probabilistic Risk Assessment, Performance Indicators, and Maintenance Rule.

Short began his career with Southern California Edison in 1976 as a Plant Engineer at San Onofre Unit 1. During his 31 years experience at SONGS, Short has held various managerial positions including Supervisor of Shift Technical Advisors, Project Manager for SONGS Unit 1 Retrofit, Nuclear Training Manager, Design Basis Documentation Program Manager, Station Technical Manager, and Site Technical Services Manager.

Short holds a Bachelor of Science degree in Engineering from the University of California, Irvine.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Daniel P. Breig

Manager, Engineering Excellence
San Onofre Nuclear Generating Station

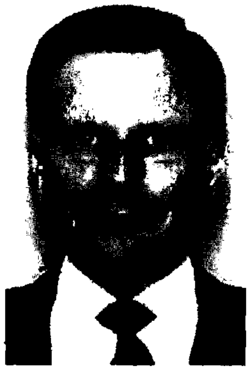
As Manager of Engineering Excellence of the San Onofre Nuclear Generating Station (SONGS), Daniel P. Breig is Assistant to the Vice President, E&TS, specifically focused on management and leadership of quality initiatives throughout the department. The primary function of the job is to create a continuous improving organization that establishes a reputation and performance level consistent with the best engineering organizations in the world.

Prior to being assigned duties as the Manager of Engineering Excellence in June 2007, Breig has held the San Onofre positions of Station Manager, Startup Manager, Project Manager, Assistant Manager, Nuclear Engineering and Construction, Site Technical Services Manager, as well as Station Technical Manager and Maintenance Engineering Division Manager. Breig has 26 years experience at San Onofre.

Breig began his career with Southern California Edison in 1974, and has held position in Engineering, Construction, Startup, and Project Management at Fossil, Nuclear, and Geothermal Power Plants.

Breig holds a Bachelor of Science degree in Electrical Engineering from the University of Arizona; a Master of Science degree in Electrical Engineering from the University of Southern California (USC); and a Master of Science degree in Mechanical Engineering from California State University at Los Angeles. Breig is also a registered Professional Engineer in the Electrical, Mechanical, and Nuclear disciplines.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company



A. Edward Scherer

Manager, Nuclear Regulatory Affairs
Southern California Edison

As Manager of Nuclear Regulatory Affairs for Southern California Edison, A. Edward Scherer is responsible for managing the interface with the U.S. Nuclear Regulatory Commission, including Plant Licensing, Regulatory Compliance, Decommissioning Licensing, Regulatory Projects (including support for radiation litigation), and Special Regulatory Projects.

Prior to joining SCE in 1998, Scherer was a Vice President at ABB Combustion Engineering. Prior to that, he served in multiple assignments, including project management, reactor engineering, plant start-up, and nuclear licensing. He was appointed Vice President for Nuclear Quality (Nuclear Power) and then served as the Vice President, Regulatory Affairs (Nuclear Fuel) and then Vice President, Business Development (Nuclear Operations).

Scherer earned a Bachelors of Science degree in mechanical engineering from Worcester Polytechnic Institute; a Masters of Science degree in nuclear engineering from the Pennsylvania State University; and a Masters in Business Administration from Rensselaer Polytechnic Institute (Hartford Graduate Center).

Scherer is a Registered Professional Engineer in the Commonwealth of Massachusetts