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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.

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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

1 ATTENDEES (Continued):

2 Dr. Graham Wallis, Member

3

4 ACRS Staff

5 Maitri Banerjee

6 David Bessette

7 Jamila Perry

8 Girija Shukla

9

10 Region IV Staff

11 Bruce Mallett, Regional Administrator

12 T. Pat Gwynn, Deputy Regional Administrator

13 Dwight Chamberlain, Director, Division of Reactor Safety

14 Roy Caniano, Deputy Director, Division of Reactor Safety

15 Tony Gody, Chief, Operations Branch

16 Michael Hay, Chief, Projects Branch C

17 Linda Howell, Chief, Response Coordination Branch

18 Linda J. Smith, Chief, Engineering Branch 2

19 Dr. D. Blair Spitzberg, Chief, Field Cycle &

20 Decommissioning Branch

21 David P. Loveless, Senior Reactor Analyst

22 John D. Hanna, Senior Project Engineer

23 George Replogle, Senior Project Engineer

24 Kelly Clayton, Senior Operations Engineer

25 Wayne Walker, Senior Project Engineer

1 Greg Warnick, Senior Resident Inspector
2 Joseph L. Lopez, Human Resources Management Specialist
3 James F. Drake, Operations Engineer
4 Paul J. Elkmann, Emergency Preparedness Analyst
5 Robert Latta, Coordinator for New Reactors
6 Larry Ricketson, Health Physics Inspector
7 Don Stearns, Health Physics Inspector
8 Mark Haire, Senior Operations Engineer
9 Tom Stetka, Senior Operations Engineer
10 Claude E. Johnson, Chief, Branch A
11 Joseph Bashore, Project Engineer, Division of Reactor
12 Projects
13 Gwen Ryan, summer engineering associate
14 Hasan Abuseini, reactor inspector, Engineering Branch 2
15 Mike Chambers, Project Engineer, Division of Reactor
16 Projects
17 Brian Larson, Operations Engineer, Division of Reactor
18 Safety
19 Brian Tindell, Operations Engineer, Division of Reactor
20 Safety
21 Greg Werner, Senior Project Engineer, Division of Reactor
22 Projects
23 Office of NRR Staff
24 F. Paul Bonnett, Senior Reactor Analyst

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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)

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P R O C E E D I N G S

1
2 MR. MAYNARD: Good morning. Let's go ahead and
3 get the meeting going. I'd like to call the meeting to
4 order.

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

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

15 So, Tony?

16 MR. GODY: Thank you.

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

24 Before we start, I'd like to point out some
25 administrative things. This is a public meeting, and the

1 meeting is between the ACRS and Region IV. And should Mr.
2 Maynard wish to open the floor up for public comments,
3 he'll do that at some point later in the meeting.

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

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

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

25 And I guess before I start, would you have any

1 other comments you'd like to make before I turn it over to
2 Pat Gwynn, sir?

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

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

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

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

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

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

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

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

1 straight.

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

6 So, Dr. Mallett?

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

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

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

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

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

1 MR. GWYNN: Let's do that.

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

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

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

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

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

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

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

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

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

25 MR. RICKETSON: Good morning. My name is Larry

1 Ricketson; I'm a health physics inspector.

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

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

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

8 (General laughter.)

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

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

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

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

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

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

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

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

25 MR. ABUSEINI: Good morning. Hasan Abuseini,

1 reactor inspector, Engineering Branch 2.

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

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

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

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

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

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

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

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

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

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

25 MR. TINDELL: I'm Brian Tindell; I'm with the

1 operator licensing staff here in Region IV. And if you
2 have any needs, then myself or Tony Gody is the person to
3 talk to.

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

5 MR. TINDELL: Absolutely.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

24 DR. SHACK: Especially with Professor Wallis.
25 (General laughter.)

1 DR. MALLET: I would add that last year, in
2 2006, the state of Mississippi asked the Agency if they
3 could have one regulator, because they were regulated for
4 materials programs by Region I and they were regulated by
5 Region IV for the reactor program. So we changed that
6 roadmap, if you will, to have the state of Mississippi
7 regulated by Region IV entirely.

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

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

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

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

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

1 area?

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

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

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

21 I'd also indicate -- I said six hours to get
22 from here to south Texas. You can drive to south Texas or
23 you can fly to south Texas; either way, it takes about six
24 hours. You can only fly to Columbia Generating Station
25 and get there in a reasonable period of time. It takes

1 seven hours to get from here to Columbia Generating
2 Station, and that's because the Dallas/Fort Worth airport
3 is such a great commodity for us. It really facilitates
4 our ability to inspect and to respond to emergencies.

5 Does that answer your question?

6 DR. MALLETT: Well, I --

7 DR. CORRADINI: Yes.

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

10 DR. CORRADINI: Yes, sir.

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

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

22 Region II does not have a program any more;
23 that was all folded into Region I about two years ago.
24 And then Region II has the fuel cycle program for all the
25 regions. They run that for the whole country. Region III

1 has about 7- or 800 licensees. And Region I will, once
2 Pennsylvania goes agreement, have maybe 1,200 licensees.

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

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

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

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

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

18 DR. CORRADINI: Okay.

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

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

1 DR. MALLET: But for nuclear materials, they
2 can.

3 DR. CORRADINI: Only nuclear materials.

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

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

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

20 DR. MALLET: That's correct.

21 DR. CORRADINI: Thank you.

22 MR. MAYNARD: I think something important to
23 know -- we've been talking about that -- as far as power
24 reactors, it's easy to compare the regions, and the
25 responsibilities are fairly similar. But when you get

1 outside of the power reactors into the other, there are
2 major differences between the regional responsibilities
3 and regional activities in those. So it's harder to
4 compare Region I versus Region IV on how they handle
5 certain things, because the divisions of responsibilities
6 are quite different outside of the power reactors.

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

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

22 Some of the plants use sea water cooling, some
23 of them are located on rivers and man-made lakes, and one
24 is even located in the desert and uses wastewater from the
25 city of Phoenix as its primary cooling supply. And so

1 this diversity, as you might imagine, creates some
2 interesting challenges for our staff. Our staff is up to
3 those challenges.

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

7 DR. MALLET: Thank you, Pat.

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

11 DR. CORRADINI: Close enough.

12 DR. MALLET: Close enough? All right. Thank
13 you.

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

23 If you look in the division that's indicated by
24 the green color -- that's our division of reactor safety.
25 And we are set up very similarly to the other regions

1 there, who'll have -- most regions will have two
2 engineering branches. Most regions will have a plant
3 support branch. Ours takes care of health physics and
4 security. You've heard some of the people here talk about
5 it. We have an operator licensing branch.

6 We did something different in this region.
7 We've combined operator licensing with the emergency
8 preparedness. We think that gets us a good mixture of
9 licensing and inspection in that branch, as well as they
10 can live off each other and feed off each other for the
11 programs that they evaluate. We've gotten a lot of good
12 insights from both ways, from the emergency preparedness
13 experts to the licensing group, and the licensing
14 examiners to the emergency preparedness group. So there's
15 --

16 DR. CORRADINI: So you intermingled them in
17 that?

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

21 One other difference you'll find is that we put
22 all our oversight of problem identification and resolution
23 inspections, safety-conscious work environment inspections
24 and the component design basis inspections into those
25 engineering branches. And Linda Smith is going to talk to

1 you later; she's probably the Agency expert --

2 I'll set you up, Linda.

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

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

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

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

1 to five or six.

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

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

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

25 We also meet every two weeks to talk about our

1 recruitment plan and, What kind of skills do we want.
2 Now, Dwight Chamberlain's on that committee, and he's
3 always asking for someone. I've never gone to a committee
4 meeting where he doesn't have the skill that he needs.
5 But I think that has helped us to recruit some unique
6 skills, like metallurgists, with plants aging and so
7 forth, a big skill that we need. So we are targeting
8 those recruitment when we go out to these schools.

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

19 We have some best practices that we've
20 developed for the Agency, and Joseph Lopez is going to
21 talk about some of those. I think another area that's
22 crucial and a challenge is maintaining the resident
23 inspector pool. We are finding now that licensees are
24 talking about building new plants and, as their work force
25 is getting older, they're recruiting our people. And so I

1 think that's great. I think we're all in this together,
2 and I think we need to get the skills we need in this
3 industry.

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

15 The third area. This is one where --

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

1 doing their jobs.

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

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

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

24 Other regions are in the same boat. Some
25 people are transferring between regions, which compounds

1 the problem. At the same time, we also bring the senior
2 residents back to the regional office. You heard George
3 Replogle was one -- I mentioned his name and several
4 others' -- that have come back to help mentor people and
5 run programs here. So you need both.

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

8 MR. MAYNARD: Good.

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

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

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

25 (General laughter.)

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

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

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

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

24 And we have posted on our wall some
25 organizational values -- and I know the principles of good

1 regulation. We try to emphasize those. And what we've
2 started doing this past couple of years is having our
3 managers go to the training classes for the individuals to
4 give some kind of an introduction as a way of re-enforcing
5 those fundamentals.

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

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

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

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

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

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

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

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

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

7 DR. MALLET: Sure.

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

17 DR. MALLET: We will talk a little bit more
18 about it.

19 DR. CORRADINI: Okay.

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

24 In our headquarters program, they are trying
25 methods to capture this knowledge, such as videos of

1 seminars, and we haven't linked in to that yet. We've
2 talked to them about it, but we haven't really linked to
3 that. I think that would be the next step, to have one
4 Agency place you could go, instead of having to go to each
5 regional office, to pick up maybe a topic of interest.

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

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

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

24 And at least at the university, what we've
25 found is going across lines in other colleges, the

1 business school in terms of case studies, other ways in
2 which you might want to draw them out to get them to know
3 things. That's what I'm curious about, because it seems
4 to me this is a really big deal.

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

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

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

1 the senior people.

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

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

12 DR. MALLETT: Yeah. We probably destroyed most
13 of their talk, but I think it is important. But I think
14 it isn't -- we are consistent. I think the approaches
15 might be a little different. Let me just quickly mention
16 --

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

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

24 I'll just quickly mention cross-cutting issue
25 or cross-cutting aspect. I think the point I would make

1 there are the challenges, first of all, for industry and
2 the NRC to get on the same page as to what's the
3 definition of each of those terms. Okay. Industry
4 typically crosses the two, and a cross-cutting issue is
5 quite different than a cross-cutting aspect.

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

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

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

1 carried away.

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

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

13 I thought you'd like that.

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

22 Dwight Chamberlain led a team where we
23 evaluated this and came up with the best practices, so
24 that all regions can use them, about a year ago. I think
25 that's helping us. There are still areas where we need to

1 work on it. And I put "alignment" because you will have -
2 - if you sit in a room with all of us, you may have five
3 or six different views of what the significance of that
4 finding is. So somewhere, you have to decide what is the
5 right one and move on from there.

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

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

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

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

1 more questions.

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

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

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

12 If anybody has any needs to -- for a telephone
13 call or to use a private room to have a discussion, Room
14 403 here by the reception desk is reserved for anyone who
15 needs it. If you need to dial out, you dial a seven to
16 get an outside line; long-distance would require a one,
17 also. Also, there's donuts and coffee in the back. And
18 if you'd like to have anything, feel free to help
19 yourself.

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

22 (General laughter.)

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

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

1 questions.

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

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

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

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

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

23 MR. LOPEZ: Yes, sir.

24 MR. MAYNARD: Now, it's my understanding that
25 between the regions and NRR there isn't a common knowledge

1 management plan; each region has been doing their own.
2 You guys -- you talk to each other, and you coordinate,
3 but each region's going to have some specific needs. So I
4 don't agree with having one plan that fits all.

5 MR. LOPEZ: Yes, sir.

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

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

15 (Pause.)

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

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

25 Bruce talked a little bit about the resource

1 planning meetings. This is the bi-weekly meetings with
2 the division directors, deputy regional administrator and
3 regional administrator with HR. And the entire intent of
4 that meeting was to manage the human capital.

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

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

12 (Pause.)

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

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

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

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

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

4 MR. LOPEZ: Yes, sir.

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

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

12 DR. CORRADINI: Okay.

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

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

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

24 MR. MAYNARD: As far as those going to the
25 industry, my gut feeling is that probably at this point

1 there's more coming from the industry to the NRC --

2 MR. LOPEZ: NRC.

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

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

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

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

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

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

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

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

25 Let's see. I'll bypass double encumbering and

1 rotational assignments.

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

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

8 MR. LOPEZ: Yes, sir.

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

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

1 DR. CORRADINI: If I just could --

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

4 (General laughter.)

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

8 MR. LOPEZ: Engineering associates.

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

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

18 DR. CORRADINI: That's good.

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

23 DR. CORRADINI: Yeah. The only reason I asked
24 it in that way is that sometimes -- we always think we
25 know how the younger folks learn, and I'm convinced that

1 we don't. But if you ask them, they'll actually give you
2 ways that you would have never thought of to actually
3 provide information and get them to be more motivated into
4 what they learn.

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

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

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

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

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

1 DR. MALLET: Well, we --

2 MR. MAYNARD: I asked for a reason.

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

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

16 (General laughter.)

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

20 MR. LOPEZ: Any other questions?

21 (Pause.)

22 MR. LOPEZ: Roy?

23 MR. CANIANO: Thank you, Joseph.

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

1 Region IV.

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

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

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

23 Last year, we had an individual, Micah Bikerra
24 [phonetic], who was one of our summer hires here. We were
25 very fortunate, by the way. We have hired Micah now, and

1 he is part of the NSPDP program. He gave a fantastic
2 seminar associated with metallurgical properties with some
3 real-life examples.

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

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

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

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

23 So some of the topics that we've included in
24 some of our seminars. I gave a presentation last year on
25 an AIT that I had the opportunity to lead back in the

1 early '90s at Point Beach that was associated with a
2 hydrogen burn with a dry cask storage device. We gave a
3 presentation here of an IIT that happened at TMI that was
4 a security event that happened back in the '90s.

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

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

18 What we try to do is limit the discussion to
19 about 60 minutes, and then we open it up for Q's and A's
20 afterwards. The attendance is fairly well. You know,
21 considering that we are a regional office where we do have
22 a lot of our staff that are out at the resident sites, we
23 will still get 30 to 50 people in attendance to these
24 seminars. We also open them up via telecon now to the
25 resident inspectors so they can call in and they can

1 listen to the dialogue. And again, we've been fairly
2 successful with regard to that initiative.

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

6 Yes?

7 DR. CORRADINI: Could I just one question?

8 MR. CANIANO: Sure.

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

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

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

25 DR. CORRADINI: Okay. Thank you.

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

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

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

22 We talk about operating experience with our new
23 staff. And for the new staff that are in the office, if
24 they're not at a training session, it's well attended.
25 And I would say on the average we may have six to eight

1 people that stick around after that morning meeting and
2 talk to our senior risk analysts, again, about technical
3 issues, just to gain an understanding of, you know, What
4 is the significance of this event that we just talked
5 about. So that, I think, works fairly well.

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

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

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

23 Joseph and I were chatting just the other day.
24 And from an HR perspective, there are some things we can
25 open up that would be non-technical in nature but, again,

1 would be sharing of information for a lot of our newer
2 staff. Another thing that we're going to try doing is
3 videotaping the sessions.

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

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

15 MR. CANIANO: They can do it by --

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

17 MR. CANIANO: Exactly.

18 Any additional questions or comments regarding
19 that?

20 DR. MALLETT: Before Roy leaves us, another
21 area we're looking at, but we haven't gotten too far yet.
22 I've talked to the industry reps and the vice presidents
23 of the plants and told them, Why don't we get together;
24 you have seminars, and we have them; why can't we share
25 expertise. And they're game to do that; we just haven't

1 figured out a way to structurally do it yet. But I think
2 that would be great if we could share those.

3 MR. MAYNARD: I agree.

4 Thank you.

5 MR. CANIANO: Okay.

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

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

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

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

19 Can you hear me in the back?

20 (Pause.)

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

1 all outages."

2 (General laughter.)

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

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

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

17 DR. BONACA: All right.

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

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

25 DR. BONACA: Okay.

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

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

10 MR. HANNA: Sure.

11 DR. BONACA: Thank you

12 MR. HANNA: Is that a little bit better?

13 DR. BONACA: No.

14 (Pause.)

15 MR. HANNA: Better?

16 DR. BONACA: Yes.

17 MR. HANNA: Okay. Great.

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

25 In order to achieve this, they had to complete

1 their first ISFSI campaign, the initial ISFSI campaign.
2 Chronologically, it was the first major project to be
3 undertaken by the licensee.

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

8 DR. BONACA: What is an ISFSI?

9 MR. HANNA: That was the ISFSI.

10 DR. BONACA: What is an ISFSI?

11 MR. HANNA: Independent Spent Fuel Storage
12 Installation.

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

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

21 (General laughter.)

22 DR. SHACK: Those are all very major
23 components.

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

1 Thank you for the segue.

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

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

11 MR. HANNA: That's correct.

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

14 MR. HANNA: That is correct.

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

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

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

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

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

25 MR. MAYNARD: How long did this whole operation

1 take?

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

4 MR. MAYNARD: So three months?

5 MR. HANNA: -- from start to finish.

6 MR. MAYNARD: Three months?

7 MR. HANNA: That's correct.

8 MR. MAYNARD: That's still incredible.

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

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

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

21 So I would also point out here that Region IV
22 used a lot of operational experience from plants like ANO
23 and Turkey Point to inform our inspection planning and to
24 respond to issues when they arose, such as the containment
25 voiding that I was talking about, much in the same way

1 that OPPD benefitted from the use of Bechtel as their
2 contractor, which had done many other major projects, we
3 benefitted from using operational experience from other
4 sites within our region and from outside our region.

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

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

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

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

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

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

20 MR. HANNA: Right.

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

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

1 fire.

2 DR. WALLIS: And they weld it up again?

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

5 DR. SHACK: It's a thermite reaction.

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

7 DR. SHACK: It's a thermite reaction.

8 MR. HANNA: Sure.

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

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

13 MR. HANNA: Oh.

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

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

16 DR. CORRADINI: And you weren't expelled?

17 (General laughter.)

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

21 As I alluded to before, it was anticipated that
22 there would be lots of problems that would occur with
23 design fit-up of the major components, especially given
24 the fact that this has been a problem for other licensees
25 and that this licensee had problems with the control of

1 contractors during the previous outage. Counter-
2 intuitively, many of the problems that we did find were in
3 areas where the licensee had historically performed well.

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

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

17 DR. WALLIS: I have a question.

18 MR. HANNA: Yes, sir.

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

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

1 Westinghouse facility. It's about 1,400 pounds or so. So
2 what they were doing was pressurizing with the charging
3 pumps or actually positive displacement pumps. And that's
4 what caused it. That's why it's much higher than the
5 1,400 pounds.

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

13 DR. MALLETT: John?

14 MR. HANNA: Yes, sir.

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

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

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

25 The second criterion was contributing causes

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

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

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

23 MR. HANNA: With respect to human performance
24 or other cross-cutting issues, the ROP is -- it does not
25 care, for lack of a better word, what was done within that

1 inspection year. It does not give credit for folks that
2 tend not to be ambitious and do extra things. So if -- I
3 don't know. That's probably not the politically correct
4 way to put that.

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

7 (General laughter.)

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

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

19 MR. HANNA: Yes.

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

24 MR. MAYNARD: And I'm not asking for your
25 answer in this case or what -- I just -- I do think that's

1 important in the process, because we don't want the
2 process to discourage people from doing things just to
3 minimize.

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

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

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

15 So I'm sorry, John.

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

22 Specifically, these issues involved only one or
23 two departments, operations and health physics. They were
24 very tightly defined. These occurred within a very narrow
25 window temporally, and all involved unusual plant

1 configurations or undesirable consequences. So you take
2 these three criteria, and we met those. And the fact that
3 it was very tightly defined -- we had reason to believe
4 that -- essentially, it's not data scattered all over the
5 place. This is a very narrow area.

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

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

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

12 MR. GODY: I can --

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

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

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

25 DR. SHACK: Why does it sound as if we're down

1 to Criterion 3 that keeps us from going?

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

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

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

18 (Pause.)

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

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

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

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

16 The safety consequences for having this valve
17 installed backwards were that it would virtually eliminate
18 any water being sprayed from that header for that train
19 and, secondly, if the licensee were to respond to an
20 accident which would not allow containment entry,
21 operators would have induced the LOCA themselves by
22 transitioning to shutdown coolant. Say they have a small
23 break load versus one -- they put the shutdown coolant
24 exchangers in service, and they're stepping through it,
25 but this valve, being installed backwards, would then

1 induce the LOCA, and that made the safety consequence of
2 this issue much higher.

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

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

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

12 MR. HANNA: There's two.

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

15 MR. HANNA: They did inspections, extended
16 condition inspections, when this condition was found to
17 verify that the other one was installed properly.

18 One of the issues that we have with the
19 licensee, if I can go back here, is that they didn't have
20 a testing -- an adequate test to make sure that that was
21 installed correctly. If they had done a visual
22 examination; if, say, they had pressurized the line with
23 air -- obviously, you don't want to spray down the
24 containment with water to test the valve, but they could
25 tested it with air or any number of things they could have

1 found that it was inadequate. They did check the operate
2 train before they went further.

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

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

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

24 So based on two white inputs, this caused us to
25 move the licensee to Column 3 of the action matrix. The

1 actions taken so far by the Agency have been, as I
2 mentioned, moving them to Column 3, informing them with a
3 revised assessments letter of that action, and we told
4 them in that letter that we would perform a 95002
5 inspection and with the date to be determined.

6 Essentially we have to wait for the licensee to tell us
7 that they're ready for that, and then we will schedule it.

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

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

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

16 MR. HANNA: Yes. That is correct.

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

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

22 DR. SHACK: Well, I mean if --

23 MR. HANNA: -- inspected by --

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

1 MR. HANNA: 191. That's --

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

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

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

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

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

20 DR. SHACK: Oh. So --

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

24 MR. HANNA: That's correct.

25 MR. MAYNARD: But this was just an interim

1 measure, not intended to be their final measure, as I
2 understood it.

3 MR. HANNA: That's correct.

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

7 MR. HANNA: Right.

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

11 MR. HANNA: That is correct.

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

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

18 MR. HANNA: It starts to curve around --

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

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

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

25 DR. SHACK: Yes.

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

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

6 MR. GODY: Okay.

7 Thank you, John.

8 MR. HANNA: Okay.

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

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

22 So what I wanted to do real quickly this
23 morning, because I know we're behind, is go over some of
24 the regional initiatives that are basically above and
25 beyond the oversight process as far as the procedures that

1 inspectors use, try to talk about ways in which the region
2 gains consistency throughout our inspection efforts, the
3 way in which we share information relative to the
4 inspection process, and the mechanisms by which we
5 disseminate operating experience throughout the inspection
6 staff.

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

15 DR. SHACK: And STAR means what?

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

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

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

1 then, we've written approximately 80 stars.

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

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

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

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

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

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

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

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

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

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

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

18 DR. WALLIS: So someone does the engineering
19 study?

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

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

23 MR. HAY: Well, I can give you a "for example,"
24 because it varies. Out at Palo Verde, when that voided
25 piping was identified, they first of all tried to have it

1 modeled at like a university using a very small-scale
2 piping. They also had a contractor try to analyze the
3 condition, and they weren't getting the exact same type of
4 results. So they then went to a larger-scale model and
5 ultimately went to a full-scale model. And it took them
6 about --

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

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

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

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

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

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

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

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

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

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

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

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

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

1 is at.

2 DR. WALLIS: Right.

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

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

8 MR. HAY: Excuse me?

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

11 MR. HAY: Oh, definitely.

12 DR. WALLIS: Okay.

13 MR. HAY: Definitely.

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

22 And we do what are called site capsules. Where
23 some important event or a very technical issue was
24 identified, we'll have that resident or senior resident
25 that was involved spend about 15 or 20 minutes and go over

1 the details of that event or of that issue as a way to
2 share those experiences.

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

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

22 There's also another write-up that deals with
23 voided piping that was found at Comanche Peak. And this
24 write-up even talks about, you know, These concerns were
25 found at Palo Verde, and this licensee didn't use that OE

1 very effectively to basically identify almost the exact
2 same problem. So that's another vehicle that we use to
3 share information.

4 MS. BANERJEE: How often are these issued?

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

6 MS. BANERJEE: How often are these issued?

7 MR. HAY: Oh.

8 MS. BANERJEE: These things.

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

13 MS. BANERJEE: Okay. Thank you.

14 MR. HAY: You're welcome.

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

23 DR. WALLIS: So you need that every morning?

24 MR. HAY: Every day, Monday through Friday.

25 That's --

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

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

5 (General laughter.)

6 DR. WALLIS: A good day?

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

9 One other thing that we do during --

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

12 MR. HAY: That's correct.

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

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

1 plan with respect to engineering activities.

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

13 DR. MALLETT: Mike, why do we do this? Why do
14 --

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

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

1 sort of information, and our inspection staff does
2 actively use it.

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

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

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

24 It really gives you just some fundamental
25 things that we know are important for them to look at on a

1 daily basis, because, you know, typically, when things are
2 different than what they were in the past, there's a
3 reason for why they're different, and they need to
4 understand those reasons. And these tools really focus on
5 those sorts of fundamentals.

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

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

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

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

15 MR. HAY: That's correct.

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

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

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

22 MR. HAY: Right.

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

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

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

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

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

8 (Whereupon, a short recess was taken.)

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

13 Mr. Walker?

14 MR. WALKER: That's correct.

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

21 Just as a little background, Cooper was the
22 first plant in our region that really, I guess you could
23 say, fully exercised the reactor oversight process. The
24 reactor oversight process went into effect in the late
25 '90s/early 2000 time period, and Cooper actually got into

1 this process fairly heavily in around the 2001 time
2 period.

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

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

19 Also, they did not make timely off-site
20 notifications following an alert declaration as a result
21 of a fire in a potential transformer. And then lastly,
22 when they were staffing their emergency response
23 facilities during that event, they didn't -- they weren't
24 able to do it within the required time following the
25 declaration of the alert. And that's the four issues that

1 actually got them into the repetitive degraded cornerstone
2 position.

3 DR. WALLIS: You said, Degraded core?

4 MR. WALKER: Degraded cornerstone.

5 MR. MAYNARD: Cornerstone.

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

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

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

12 DR. WALLIS: A degraded core?

13 MR. WALKER: Yes.

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

16 DR. CORRADINI: In simulation.

17 MR. MAYNARD: In simulation, meaning --

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

20 DR. CORRADINI: Right.

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

22 MR. WALKER: I'm sorry.

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

24 MR. WALKER: In the bullet I have up here, the
25 95001 -- if you're familiar with the reactor oversight

1 process, the 0305 manual chapter. So basically what we
2 did is -- we went down a path of -- our initial inspection
3 involved a 95001, which was for some of the first issues.
4 And once we did that inspection, we determined that we
5 didn't feel the licensee had adequately addressed and with
6 enough depth the corrective actions necessary to preclude
7 this happening again.

8 So basically, we went out and did a 95002
9 inspection and came back with similar results. And then
10 after they had these four findings and were in the
11 repetitive degraded cornerstone, we went out and did a
12 95001 inspection.

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

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

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

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

6 DR. BONACA: Oh, I see.

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

8 DR. BONACA: So this was before --

9 MR. WALKER: Right.

10 DR. BONACA: -- those changes were
11 implemented?

12 MR. WALKER: Exactly.

13 DR. BONACA: Okay.

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

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

25 There had been a long history with Cooper of

1 having difficulty following through with improvement
2 plans. And as an Agency, we felt like that was the proper
3 thing to do, to issue the confirmatory action letter, as
4 allowed by the 0305 process.

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

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

25 Next slide. The -- basically, we considered

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

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

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

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

24 DR. WALLIS: Not a lot of comment?

25 MR. WALKER: No. Early on in the process, the

1 tendency to -- I should have mentioned this, too. After
2 each quarterly inspection, we did a public exit, also, at
3 the site, just -- not at the site, but just near the site,
4 in Brownville, which is a couple miles from the site.

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

14 Last slide, Brian?

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

25 I think also we learned that the ROP process is

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

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

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

23 And also, I guess what maybe did not work so
24 well is -- it just kind of gives you an idea that this
25 process can get very drawn out. And it is very much based

1 on the licensee being able to close issues out, and it
2 does take a lot of time for us to go out and inspect, and
3 it's very resource-intensive.

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

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

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

19 Linda?

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

22 DR. BONACA: Okay.

23 MS. SMITH: The latest safety culture
24 initiative really added on opportunities for the licensee
25 to do their own safety culture assessments and, also, for

1 us to assess that effort. And so the first part's still
2 the same. So the things that he worked under, that
3 program with the CAL, that's all still in place and could
4 be used that way. But they added the safety culture
5 assessments to the 95002 and 95003, and I'll talk a little
6 bit more about that in my presentation.

7 DR. BONACA: Okay. Thank you.

8 MR. WALKER: I think you were --

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

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

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

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

25 MR. WALKER: Correct.

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

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

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

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

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

18 The current 95003 procedure has approximately
19 2,500 hours of baseline inspection. Of that, NRC added
20 approximately 460 hours of baseline inspection associated
21 with the safety culture portion.

22 So we're going to have four dedicated
23 inspectors looking at safety culture aspect impact on
24 plant performance of Palo Verde. So that -- again, 2,500
25 hours is probably double that for preparation and

1 documentation. So probably a total of around 5,000 hours
2 of inspection effort will be expended just alone on the
3 initial 95003 inspection at Palo Verde.

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

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

13 MR. WERNER: Go ahead.

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

18 DR. BONACA: Okay.

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

1 programmatic.

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

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

6 DR. BONACA: All right.

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

13 MR. WALKER: Yes.

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

20 MS. SMITH: But it circles back around to the -
21 -

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

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

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

6 MR. WERNER: Yes.

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

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

18 DR. BONACA: Okay.

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

25 MR. WALKER: That's a great point. I mean we

1 really -- we struggled with that. Obviously, you can
2 imagine the licensee was putting a lot of pressure on us
3 to say, Hey, we've done enough, you know; when's enough.
4 And we came to the consensus that it was enough, you know.
5 And that's -- we made that decision. But yeah, it's a
6 subjective call.

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

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

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

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

1 with Mr. Warnick.

2 Thank you very much.

3 MR. WALKER: Thank you.

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

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

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

16 MR. WARNICK: Decline.

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

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

1 over that performance period.

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

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

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

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

23 NRC oversight at Palo Verde has identified a
24 declining licensee performance starting in 2004. A large
25 number of event-driven plant trips and power reductions to

1 deal with emergent issues occurred; many of the issues
2 involved latent organizational and programmatic issues and
3 degraded plant equipment. The number of inspection
4 findings increased from five in 2003 to over fifty in
5 2004.

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

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

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

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

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

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

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

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

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

24 DR. CORRADINI: So if you could just -- if it's
25 not too much time off your schedule. So since 1992, what

1 was -- there was a blockage or there was a partition? I'm
2 not exactly sure what --

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

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

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

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

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

1 a number of years.

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

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

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

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

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

22 MR. WARNICK: It was discovered through
23 Waterford asking about that situation. I personally was
24 not aware that it was maintained dry. That was news to me
25 as that issue came up. A lot of the people on site knew

1 it was voided, but, because it had been that way for so
2 many years, they understood, as you suggested, that, Hey,
3 the water would fill it up, and it's not going to be an
4 issue.

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

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

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

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

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

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

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

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

25 DR. WALLIS: Yes.

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

4 DR. WALLIS: Right.

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

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

9 MR. WARNICK: That's right.

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

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

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

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

24 We did give a violation for Severity Level III.
25 And that required the licensee to take actions. And in

1 fact, they recognized that there were some weaknesses in
2 their approach to those types of analyses and the rigor
3 that goes into them.

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

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

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

20 MR. WARNICK: Absolutely. And those --

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

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

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

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

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

21 The declining performance trend was not
22 corrected in 2005; that was mainly due to the licensee's
23 symptom-based and narrowly focused corrective actions.
24 Palo Verde did develop and began implementing a
25 performance improvement plan in 2005, and they determined

1 that they needed to develop and implement a plan based on
2 the downward trend that began in 2003. And that's
3 relative to the sustained high performance levels that
4 they had in previous years.

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

11 Management also determined that two events in
12 2004 -- there was a three-unit loss of off-site power
13 where all three units tripped offline, and this emergency
14 core cooling voiding issue -- revealed issues with regard
15 to various Palo Verde programs and processes that needed
16 improvement.

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

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

1 findings --

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

5 DR. APOSTOLAKIS: All right.

6 MR. WARNICK: So that's why they went to the
7 degraded cornerstone column. In 2006, we identified over
8 40 findings, so, again, a high number of findings. But
9 those were all green. And in 2007, as I get to it, we
10 identified an additional finding along with numerous
11 others, but one of more-than-green significance. And that
12 was white. And I'll talk about that in a moment.

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

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

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

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

10 DR. APOSTOLAKIS: There you go.

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

17 As we looked at the criterion in manual chapter
18 0305, the criterion was satisfied. And because of that,
19 we issued in our assessment letters substantive cross-
20 cutting issues in human performance and PIR.

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

23 MR. WARNICK: Okay.

24 DR. APOSTOLAKIS: A high number of allegations,
25 30 green. If there were ten, would you still conclude

1 that there is a cross-cutting issue? If there were five?
2 Is it the number that determines what it is, or is it -- I
3 mean if it's judgment, it's judgment.

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

6 DR. APOSTOLAKIS: No.

7 MR. WARNICK: That's correct.

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

10 MR. WARNICK: Okay.

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

12 MR. WARNICK: There's --

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

15 MR. WARNICK: I hear you.

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

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

19 MR. WARNICK: Yeah, that's right.

20 DR. APOSTOLAKIS: Could you repeat those?

21 MR. WARNICK: Sure.

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

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

25 DR. APOSTOLAKIS: Yes.

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

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

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

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

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

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

21 DR. APOSTOLAKIS: Yes. Thank you.

22 MR. WARNICK: Okay.

23 DR. MALLETT: Let me add something. This time,
24 in this cycle of reviews that we just finished, we had in
25 particular a long discussion on one of the licensees that

1 had a number of findings tagged with cross-cutting
2 aspects. I don't remember the number, but it met the
3 first criterion.

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

11 MR. WARNICK: Thanks, Bruce.

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

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

18 DR. APOSTOLAKIS: Every day?

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

24 DR. APOSTOLAKIS: And the mid-cycle?

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

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

3 DR. APOSTOLAKIS: I see.

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

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

8 MR. WARNICK: That's exactly right.

9 DR. APOSTOLAKIS: Oh. Okay.

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

17 DR. APOSTOLAKIS: Okay. Thank you.

18 MR. WARNICK: Okay.

19 All right. We're to 2006 now. They're -- the
20 licensee at Palo Verde is in the degraded cornerstone
21 column, and that was based on the yellow finding that was
22 carried forth from the fourth quarter of 2004. Palo Verde
23 -- they did present their performance improvement plan
24 during a March 2006 public meeting. It appeared to be a
25 decent plan; however, they continued to struggle with the

1 implementation phase due to the high number of issues and
2 events that redirected their attention.

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

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

22 I was the team leader for the follow-up 95002
23 inspection that we performed. We completed that in July
24 2006. This inspection was performed just after the
25 identification of a potentially-safety-significant issue

1 related to spray chemistry.

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

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

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

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

20 MR. WARNICK: Certainly. Through our baseline
21 inspections and some self-revealing events, it became
22 evident that heat exchangers that are cooled by the spray
23 pond water, specifically the diesel inner-cooling heat
24 exchanger, was -- the performance of them was degraded to
25 the point that as they started to take off the end valves

1 and inspect, they call kind of a gooey substance in there,
2 and it was coating all of the tubes, degrading heat
3 transfer.

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

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

19 So the same types of behaviors that were
20 necessary to deal with the spray pond chemistry issues --
21 again, it was a long-standing problem that had revealed
22 itself only through equipment degradation. Their response
23 once that degradation became apparent was untimely, and
24 their evaluations were shortsighted. And many times, we,
25 the NRC, had to step in and ask them for more information

1 related to an evaluation to give a good basis for why --
2 operability issues.

3 While the licensee developed corrective actions
4 in late 2005 to address the performance issues, they
5 continued to struggle with effective implementation in
6 2006. And as I mentioned, I was the team leader for that
7 inspection. And I recommended that we leave the yellow
8 finding open because they hadn't fixed their problems and
9 corrective actions were lacking in those areas I
10 discussed, as well as that their effectiveness measures
11 were inadequate in the ways that they determined that
12 continued performance was sustained.

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

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

25 And additionally -- I told you that we

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

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

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

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

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

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

20 MR. WARNICK: That's right.

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

23 MR. WARNICK: That's right. And they've
24 struggled with that. And that has been our ongoing
25 assessment and one of the main reasons for why they have a

1 substantive cross-cutting issue in problem identification
2 and resolution that has been going on three years now.

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

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

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

24 We documented the cross-cutting issue, despite
25 what the licensee believed, because we satisfied the three

1 criteria that we talked about before. Since it was a
2 documented issue, the licensee then initiated an
3 investigation to understand the issue.

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

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

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

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

20 We had a number of findings that came out of
21 that, as well as other issues. And as soon as we had the
22 new information necessary to make the assessment with the
23 0305 criterion, we used that tool that we have, our
24 guidance document, and issued the human performance
25 substantive cross-cutting issue. Still the licensee

1 didn't believe it until many months later, when they
2 themselves did a screening analysis and reached the same
3 conclusions we did.

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

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

20 This was followed by multiple examples of a
21 failure to follow the operability determination process
22 and culminated with several self-revealing and licensee-
23 identified findings over the 2005 to 2006 time frame for
24 operator human performance error, when my follow-up and
25 the direction that I provided to my inspectors revealed

1 that the errors were driven by a self-imposed schedule
2 pressure.

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

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

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

1 conditions.

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

11 Any questions?

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

14 MR. WARNICK: That's correct.

15 DR. APOSTOLAKIS: Since 2004?

16 MR. WARNICK: Since the fourth quarter of 2004.
17 And that yellow finding will also be addressed through the
18 95003 inspection team coming up.

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

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

24 DR. APOSTOLAKIS: But let's say they don't want
25 to do it. Does the ROP say -- at some point, you know,

1 you decide enough is enough and you take more severe
2 action?

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

10 DR. APOSTOLAKIS: Is the --

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

19 So what we said -- this last year when we
20 reviewed this oversight program in our annual review, the
21 Agency's action review meeting, we said there's something
22 wrong with a licensee that stays in this area forever and
23 doesn't fix these programmatic issue. So we -- speaking
24 from an old health physicist, you crank up the gain a
25 little bit on the potentiometer, and you -- of course, the

1 new people don't talk that way, but, anyway, I crank up
2 the gain.

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

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

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

23 So I wanted to add one more thing that Greg
24 doesn't have in any of his slides. The key to any
25 inspection program, to me, are the inspectors, whether it

1 be the residents or the regional inspectors. And early
2 on, long before we put cross-cutting issues in place, they
3 were saying, There are problems at this site in how
4 they're performing. And they started showing up about a
5 year after they told us this in performance issues at the
6 plant.

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

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

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

19 DR. CORRADINI: Right, this one.

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

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

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

25 DR. CORRADINI: So before that occurs --

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

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

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

22 And I've absolutely seen over the last six
23 months or so a change in direction from the licensee.
24 They've actually changed a number of licensee management,
25 senior management. And so I'm out there interacting with

1 the front-line people day to day. There's a lot of
2 excitement out there. The employees recognize, too, that
3 there have been some onsite problems and, yet, things
4 didn't change, due to the culture that was there.

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

8 DR. CORRADINI: Positively, you're saying?

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

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

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

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

1 deteriorating? What was the reason?

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

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

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

19 And what we're doing -- under our current
20 process as the 95003 inspection team, as part of their
21 scope, they're looking back to some of the diagnostic
22 assessments that were done, some of the key changes. Re-
23 engineering is something that Palo Verde talks about that
24 was done in -- I believe it was late -- around 1994 or so
25 -- some of these big changes or key changes at the site

1 that took place, to see if we can go back and identify
2 maybe some of the contributing causes to their performance
3 declining to where they are today.

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

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

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

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

5 DR. APOSTOLAKIS: Yeah. That's good.

6 MR. MAYNARD: I think we need to be --
7 Have you got another question?

8 DR. APOSTOLAKIS: Yeah.

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

11 DR. APOSTOLAKIS: Yes.

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

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

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

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

25 DR. APOSTOLAKIS: But the question is really

1 whether it's the ROP itself that is adding the value,
2 because wouldn't you say that before the ROP came along,
3 you would still have found these things? What is the
4 specific thing that the ROP added?

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

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

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

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

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

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

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

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

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

15 DR. APOSTOLAKIS: Yes. Thank you.

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

25 The other thing is we have built into the

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

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

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

20 The other thing for the record that I think
21 needs to be stated: We've heard the Region IV's
22 perspective on the Reactor Oversight Process and on these;
23 we did not invite the licensees in or provide any time for
24 them. They may or may not have any different perspective.
25 I mean we just need to acknowledge that. I don't think

1 there has been anything said that would be misleading or
2 anything, but we have only heard the one side of it for
3 those -- the purposes here.

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

6 MR. GODY: Thank you.

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

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

18 (Whereupon, a luncheon recess ensued.)

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

24 One question I'd have for you. I'm not sure.
25 Are members of the public invited on this part of the

1 tour? Or --

2 MR. GODY: No, they're not.

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

5 MR. GODY: Thank you, sir.

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

10 (Whereupon, participants toured the incident
11 response center.)

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

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

19 DR. SPITZBERG: Okay.

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

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

25 Thank you. My name is Blair Spitzberg. I'm

1 the chief of the fuel cycle decommissioning branch here in
2 Region IV. And my branch is one of the branches that
3 captures a couple of areas that intersect with the reactor
4 programs.

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

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

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

22 There's a lot of reasons for that, one being
23 the fact that we had an accident at Three Mile Island, and
24 the Chernobyl accident led to a lack of confidence on the
25 part of the public. But nevertheless there was five

1 reactors in Region IV alone that decided to prematurely
2 shut down.

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

10 MR. MAYNARD: You might clarify it's San Onofre
11 1.

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

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

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

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

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

25 I want to focus a little bit on the San Onofre

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

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

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

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

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

24 DR. SPITZBERG: Yes, they -- what they do is
25 they have to -- they were proposing to send it for

1 disposal at a shallow land burial site.

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

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

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

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

9 DR. WALLIS: With concrete.

10 DR. SPITZBERG: -- low-density concrete.

11 DR. WALLIS: Oh, they filled it.

12 DR. SPITZBERG: They filled it with it, and
13 that's to immobilize the contaminants inside --

14 DR. WALLIS: I see. Okay.

15 DR. SPITZBERG: -- and make the package satisfy
16 the package requirements for transport.

17 So anyway, the licensee came to us several
18 years ago and indicated to us that they were looking at
19 options for how they would dispose of their reactor
20 pressure vessel. And I wanted to go through some of the
21 options now, because one of the things that this
22 illustrates is the problems that we have with low-level
23 waste disposal capacity in this country.

24 MR. MAYNARD: Please refresh my -- Trojan went
25 to Hanford, is that what they did with it?

1 DR. SPITZBERG: Trojan went to Hanford, and
2 they're part of the Northwest Compact, so that --

3 MR. MAYNARD: I see.

4 DR. SPITZBERG: -- they had clearance to
5 dispose of the reactor vessel there.

6 DR. SHACK: And though this is nice and
7 conveniently located, you can't --

8 DR. SPITZBERG: Yes.

9 DR. SHACK: -- go there.

10 DR. SPITZBERG: That -- well, that's right. So
11 this was the first option they looked at was putting it on
12 a rail car and transporting it to Barnwell, South
13 Carolina, which is the site over here, which is the only
14 available waste burial site, low-level waste burial site,
15 available to the San Onofre site at the time.

16 There actually is a low-level waste burial
17 site, as you're aware, Energy Solutions in Utah, but
18 they're not able to take anything other than Class A
19 waste. So the reactor vessel could not be shipped there.

20 They did not have the option to go up to the
21 waste burial site up in Washington because they're not
22 part of that compact. See, I don't --

23 DR. ABDEL-KAHLIK: Classified as what, Class C?

24 DR. SPITZBERG: It would be Class C waste. The
25 options they looked at here, when they approached the

1 railroad companies, and I'm not sure which route they were
2 looking at, but it's probably one of these two southern
3 routes. This is a map showing the rail transport routes,
4 corridors, in the U.S.

5 I refer to this -- these routes as the Vasquez
6 De Coronado route. I'm an amateur historian here. But in
7 any case, the railroads were concerned that if there was
8 an accident on one of these two routes, that it could put
9 their route out of service for a period of time that the
10 railroads apparently conveyed back to the utility that
11 they were not willing to take these -- this shipment by
12 these routes.

13 So then the --

14 DR. SHACK: But they physically could take it.

15 DR. SPITZBERG: They could take it, yes. So
16 then they turned to option two, which was transport by sea
17 barge through the Panama Canal to Barnwell, and, of
18 course, the utility had located a sea barge that was built
19 I think back before World War II, and they had deemed it
20 unsinkable because it had water tight compartments and it
21 was an --

22 MR. MAYNARD: The Titanic --

23 DR. SPITZBERG: -- unsinkable barge.

24 MR. MAYNARD: -- was unsinkable too.

25 DR. SPITZBERG: I'm sorry?

1 VOICE: So it wouldn't be able to sink.

2 DR. SPITZBERG: That's right. But in any case,
3 they were going to ship it down through the Panama Canal
4 to Barnwell via this route, which I have termed the Vasco
5 de Balboa Route.

6 Unfortunately, this route was not approved, as
7 I understand it, by the canal zone, the Panamanian were
8 concerned about transporting this type of package through
9 the canal zone and what were to happen if something were
10 to go wrong with the transport as it passed through the
11 canal. So they did not get clearance to go by this route.

12 So the next option they looked at was the
13 transport by the same barge, the unsinkable barge, around
14 Cape Horn, South America to Barnwell, and I guess I'll
15 refer to this as the Sir Francis Drake route.

16 And the problem with this is that, among other
17 things, it's a very long route, as you can tell. But the
18 State Department, as I understand it, received concerns
19 all the way up to the Secretary of State, which was then
20 Colin Powell involving concerns expressed by the South
21 American countries who would be considered safe harbor in
22 the event of some event or foul weather, or something
23 where this barge carrying this reactor vessel had to put
24 into port for whatever reason on this route.

25 So they got this feedback from these countries

1 and the State Department was opposed to this, so I think
2 the utility gave up on this idea and abandoned this.

3 So consequently here stands the Unit 1 reactor
4 pressure vessel still packaged in its transport package
5 ready for shipment with no place to go. And their plans
6 currently, as I understand it, is to leave it on site
7 until the other units are decommissioned decades down the
8 line and then dispose of it with the other reactors at
9 that time via whatever mechanism is available at that
10 time.

11 DR. WALLIS: Well, it can't be very harmless
12 for people -- very harmful for people standing around it.

13 DR. SPITZBERG: Yes, it's -- well, it's
14 relatively well shielded, but it is -- you do get some
15 radiation readings off of it. One of the things that I
16 think -- I wanted to highlight by illustrating this
17 problem that SONGS encountered with disposal of the
18 reactor vessel is that, as a healthy physicist, I think
19 most of us would be strongly in favor of going ahead and
20 disposing of this material, getting it in its final
21 resting place so that you don't have to deal with it in
22 health physic space.

23 But if you recall back to the Low-Level Waste
24 Policy Act of 1982, it laid out the format for the states
25 to encounter into agreements with other states into what

1 they call compacts. And then each of these compacts would
2 agree on developing their own low-level waste disposal
3 sites.

4 And my understanding of the compact system,
5 based on what I see, is that it was not successful in
6 developing additional alternatives for low-level waste
7 disposal.

8 DR. SHACK: Just -- in that package now, did
9 they take out things like baffle former plates or all that
10 irradiated stainless steel --

11 DR. SPITZBERG: They did take out some of the
12 internals that would have caused the package to be greater
13 than Class C, because they could not dispose of greater
14 than Class C at the low-level waste burial sites, they
15 would have to go to the high-level waste sites. And so
16 that was removed.

17 The other area in the reactor decommissioning
18 arena --

19 DR. ABDEL-KAHLIK: What happened to those
20 internal components that were removed?

21 DR. SPITZBERG: That will be packaged up and
22 put in their ISFSI and eventually sent to a high-level
23 waste disposal facility, could be Yucca Mountain, could be
24 whatever other facility.

25 (Pause.)

1 DR. SPITZBERG: Okay. The other issue that I
2 want to briefly describe in the reactor decommissioning
3 arena has to do with the Humboldt Bay facility which is on
4 the northern coast of California. Humboldt Bay, for those
5 of you that don't know, was a small BWR that operated back
6 in the '60s.

7 It was very unique in that it was right on the
8 coast, and it is also subterranean. It's been in safe
9 store since -- it's been permanently shut down since about
10 1976. And a couple of years ago when they were preparing
11 to make their plans for putting their spent fuel in dry
12 cask storage, they decided that they needed to go into
13 their spent fuel pool and do a comprehensive inventory
14 assessment of the fuel that they have there to make sure
15 that that aligned with their current records and inventory
16 of their special nuclear material.

17 In the process of doing that, they discovered
18 that there were three small rod segments that were
19 unaccounted for. And these rod segments were cut back in
20 1968 time frame. They packaged it originally with the
21 intent of shipping it off site to a laboratory for some
22 examination of the fuel and it had performed. They have
23 records that indicated that the shipment never took place,
24 and that they placed the fuel back in the pool.

25 But from that point on the records did not

1 account for where the segments were. And so when they
2 were going through and trying to reconcile the records
3 they had on hand and the fuel, that they went through
4 their inventory and visual examination with the underwater
5 cameras, and they could not account for the segments.

6 So they notified the NRC and started an
7 extensive and investigation, which took several months to
8 complete. And at the end of that search and
9 investigation, they failed to positively identify the
10 segments.

11 DR. CORRADINI: So this was spent fuel?

12 DR. SPITZBERG: This was spent fuel.

13 DR. CORRADINI: And it was three rods, or three
14 part --

15 DR. SPITZBERG: It was three segments of a
16 single rod, three 18 inch --

17 DR. CORRADINI: Three segments --

18 DR. SPITZBERG: -- segments.

19 DR. CORRADINI: -- of a single rod.

20 DR. SPITZBERG: Yes.

21 DR. CORRADINI: So it was 100 grams or
22 something?

23 DR. SPITZBERG: I don't remember the exact
24 weight -- the mass -- are you talking about the mass of
25 the special nuclear material?

1 DR. CORRADINI: Right.

2 DR. SPITZBERG: Yes, I don't remember. Do
3 you --

4 DR. CORRADINI: But -- I guess you used that
5 phrase again, but it's not special nuclear material, is
6 it?

7 DR. SPITZBERG: It's irradiated fuel.

8 DR. CORRADINI: So is that by definition, by
9 these definitions, special nuclear material?

10 DR. SPITZBERG: It is special nuclear material.

11 MALE VOICE: Yes, sure.

12 MALE VOICE: Yes, sir.

13 DR. MALLETT: About 5 percent.

14 DR. SPITZBERG: Because it's --

15 DR. MALLETT: Right around 5 percent. I don't
16 know what this --

17 DR. SPITZBERG: It was about 5 percent as I
18 recall.

19 DR. CORRADINI: Oh, so it's fresh.

20 DR. SPITZBERG: It's not -- it's irradiated
21 fuel, previously irradiated fuel. It has been burned in
22 their reactor.

23 DR. CORRADINI: So --

24 DR. SPITZBERG: But it was still very fissile.
25 Okay. So after their investigation, and, of

1 course, we were heavily involved in that investigation as
2 well from an inspection standpoint. What the licensee
3 concluded is that the most probable scenario was that
4 after the spent fuel pool clean up effort years ago,
5 they'd mistaken -- mistook these fuel rods segments for
6 low-level waste and put it in a low-level waste shipment
7 to a burial site in South Dakota I believe was the one
8 that they identified there.

9 That was the most probable scenario. They also
10 looked at all the other possible scenarios and gave weight
11 to those scenarios based on the evidence that they had
12 developed in their investigation. And subsequent to that
13 they were subject to NRC enforcement action and a civil
14 penalty.

15 The next topic that I wanted to discuss briefly
16 was to check some of the challenging Region IV inspection
17 issues in the spent fuel storage arena. I know there was
18 a question this morning about ISFSI. I just wanted to
19 make sure we're clear on the terminology here.

20 Three areas that I wanted to discuss, one, the
21 canister handling crane issues, the second being the use
22 of a lightweight transfer cask, and then I wanted to
23 discuss one case of an ISFSI construction project with
24 some ongoing legal issues.

25 On the cask handling crane issues, this was a

1 plant here in Region IV that had some seismic analysis
2 concerns with the crane supports that we identified during
3 the pre-operational inspection of their ISFSI operations.
4 We also have identified irregularities with the 125
5 percent load tests that were conducted in 1980 with the
6 cask handling crane at another site.

7 At the first site where we had the seismic
8 analysis issues, we also found lost documentation of crane
9 weld inspections back when they were originally performed.
10 We've also identified crane maintenance issues. And with
11 single failure proof cranes, one of our sites we
12 identified a number of issues in the pre-operational
13 inspection having to do with things like hoist gears were
14 dry and galled, they had inoperable systems associated
15 with the crane, including the wire rope equalizing system,
16 the bridge and trolley limit switches, the crane load
17 hang-up protection.

18 There was some gearbox lubricant issues
19 concerning whether or not they were using the proper
20 lubricant in the gearbox, and inadequate cold proof tests
21 that had been performed.

22 And so based on this, fortunately we caught
23 these in the pre-operational inspections, so it did not
24 involve the use of cranes with actual lifting of the
25 loaded canister. The licensees in all of these cases did

1 take corrective action and corrected these problems prior
2 to the initial cask loadings.

3 The next area that I wanted to talk about in
4 the ISFSI arena that we've encountered in recent years has
5 to do with the use of a lightweight transfer cask at a
6 plant in Region IV. They opted to use a lightweight
7 transfer cask due to the limitations on their cask
8 handling crane in their aux building which was limited to
9 75 tons.

10 Typical weight of a loaded canister is in the
11 neighborhood of about 100 tons, and so they needed to do
12 something if they wanted to use the 75-ton crane capacity.
13 They did this by removing about 25 tons of shielding from
14 the transfer -- from the canister and from the transfer
15 cask, and they did this under what we call the 72.48
16 process which is the equivalent of the 50.50 -- roughly
17 equivalent of the 50.59 process, the self-approval
18 process.

19 We learned about this prior to the actual
20 loading and we did our pre-operational inspections and
21 started asking questions about the 72.48 process that they
22 put this through. Some of the things that we found out is
23 that they removed enough of the shielding that they would
24 have, for design basis, fuel radiation levels on a loaded
25 canister up to 53 Rem per hour.

1 They also had planned -- in order to compensate
2 for the reduction in shielding, they planned to use remote
3 crane operations, including cameras and laser sites, which
4 is well and good until a problem occurs or if it gets hung
5 up there. Then you have to counteract the problem with
6 the remote handling.

7 The canister drain-down was also going to occur
8 earlier than specified in the FSAR, which potentially
9 affected the vacuum drying times tech spec limit for the
10 canister. And this is a tech spec limit that is intended
11 to protect the cladding on the fuel.

12 After we looked at this and we got our spent
13 fuel project office involved and the experts up there, we
14 did a lot of analysis and determined that the changes that
15 were being proposed by the licensee could not be self-
16 approved under the 72.48 process.

17 We caught this before they loaded -- were
18 loading casks, so the licensee subsequently sought and
19 received NRC exemption, but the exemption that they sought
20 was only for the old cold fuel, it was not for the design
21 basis fuel, and exemption limited them to being able to
22 load only four casks.

23 And so now we have this licensee up there and
24 they're starting to plot their future in terms of what do
25 they need to do now to load casks with the 75-ton crane,

1 and I think what they're contemplating now is upgrading
2 the rating on the crane, putting in a new crane
3 essentially.

4 As a result of this, there was a regulatory
5 issue summary that was issued in 2006 that contained a lot
6 of the lessons learned from this episode.

7 MALE VOICE: This is kind of interesting here.

8 DR. ABDEL-KAHLIK: They were going to go
9 through this process through 72.48. What was the
10 mechanism by which you sort of caught them in mid-stream
11 and said, no, you can't do it, you have to have approval?

12 DR. SPITZBERG: We -- our program requires us
13 to do a pre-operational inspection prior to the first cask
14 loading at each site. And so as part of that pre-
15 operational inspection, we do look at the 72.48 process
16 that the licensee uses, because all of these licensees
17 that use these pre-approved casks, they always make some
18 site specific changes to the way that they're going to us
19 them.

20 And so we look at the 72.48 process to make
21 sure it's consistent and properly applied. And that's
22 where we caught it, is in the pre-operational preparations
23 to load casks.

24 DR. ABDEL-KAHLIK: So the vendor of this cask
25 did not seek approval of this --

1 DR. SPITZBERG: Yes.

2 DR. ABDEL-KAHLIK: -- modified --

3 DR. SPITZBERG: That's correct.

4 DR. ABDEL-KAHLIK: -- cask with one --

5 DR. SPITZBERG: That's correct.

6 DR. ABDEL-KAHLIK: -- shield.

7 DR. SPITZBERG: And if you were to talk to the
8 vendor, they would probably contend that they still don't
9 need to seek approval. But it was our agency decision
10 that in this case they did.

11 The last area I wanted to briefly talk about is
12 the inspection of the Diablo Canyon ISFSI. You're
13 probably aware that there have been some recent legal
14 challenges regarding the consideration of terrorist
15 attacks in conducting the Diablo Canyon ISFSI
16 environmental reviews.

17 In the meantime, while this has been going on,
18 Region IV has continued to conduct our time sensitive
19 inspections of the construction and pre-operational areas
20 of the Diablo Canyon ISFSI because the licensee has
21 proceeded to go down the path of constructing their ISFSI,
22 the pad, the transporter, a lot of the infrastructure that
23 supports their eventual use of this system has been under
24 construction. and so we've performed our inspections
25 during the sensitive phases of those construction

1 activities.

2 Inspections to date include the fabrication of
3 the transporter, which in the case of Diablo Canyon, it is
4 in a seismically -- elevated seismic area out there, and
5 so they do have an important safety transporter, and we've
6 observed -- inspected the fabrication of that transporter,
7 the construction of the transport roadway, the ISFSI pads,
8 and the transfer facility for the casks, and also the
9 installation of the grouted rock anchors and transporter
10 seismic tie-down.

11

12 We've conducted these inspections as if there
13 were no ongoing legal challenges to the process.

14 DR. CORRADINI: So the challenges are for the
15 eventual granting of the license for the dry cask storage
16 facility.

17 DR. SPITZBERG: Yes. Well, essentially the
18 challenges would intervene in their ability to load
19 casks --

20 DR. CORRADINI: Right.

21 DR. SPITZBERG: -- under this --

22 DR. CORRADINI: I sorry.

23 DR. SPITZBERG: Yes.

24 MR. SHUKLA: So the license has been granted?

25 DR. MALLETT: Let's make that clear. They have

1 a license to load fuel. We've approved it.

2 DR. SPITZBERG: Yes.

3 DR. MALLET: But since that time it's been
4 challenged in the courts --

5 DR. SPITZBERG: Correct.

6 DR. MALLET: -- that the environmental
7 assessment was not adequate because it didn't consider --

8 DR. SPITZBERG: Consider terrorist attack.

9 DR. MALLET: -- security, terrorism. That's
10 what we resolved in that analysis.

11 DR. SPITZBERG: Thank you. So with that, I'll
12 just end with -- I know you're going to San Onofre, so
13 I'll just end with another depiction of their ISFSI out
14 there with their little transporter here that -- and a
15 couple of NRC inspectors down below.

16 DR. CORRADINI: So I guess -- I have to go back
17 to the one where the fuel segments are kind of missing.

18 DR. SPITZBERG: Yes.

19 DR. CORRADINI: So you fined them and then?

20 MALE VOICE: We didn't fine them.

21 DR. SPITZBERG: We didn't fine them.

22 DR. CORRADINI: Didn't fine -- not -- you
23 didn't fine -- the segments -- they were civil penalty
24 fined.

25 DR. SPITZBERG: Yes.

1 DR. CORRADINI: And then the operator -- what
2 is -- legally it's done now, it's just somewhere in the
3 environment, end of story?

4 DR. SPITZBERG: Well, the scenario that they
5 believe has the most credibility, based on all the various
6 scenarios that could have occurred with the fuel, was that
7 it went to a low-level waste burial site with some other
8 low-level waste by mistake.

9 DR. CORRADINI: And in your calculations --

10 DR. SPITZBERG: Now, there is still the
11 potential that the fuel is still there in the pool in an
12 unrecognized form, or in another canister that they --
13 mixed in with some other fuel and they don't recognize
14 exactly -- there were not serial numbers on them.

15 DR. CORRADINI: Right. I understand. But I
16 guess my mind's going on a few things like so it must have
17 been a small enough amount of fuel that you do -- there's
18 some sort of radiological scan of low-level waste coming
19 off site to make sure that what you think is there is
20 approximate in terms of the radiation level that's out
21 there. So it's got to be low enough that it passed that
22 screen if it went to the low-level waste site.

23 DR. SPITZBERG: That's correct. It --

24 DR. CORRADINI: So did they do a
25 radiological --

1 DR. SPITZBERG: They did look at their shipping
2 records for their waste and they did find that the
3 radiation levels for those shipments met transportation
4 regulations. However, these are usually low-level waste
5 shipments from nuclear plants can include spent resins --

6 DR. CORRADINI: Yes, it depends --

7 DR. SPITZBERG: -- and other things. So it can
8 be pretty hot.

9 DR. CORRADINI: Right.

10 DR. SPITZBERG: And it has to be -- for
11 example, if you ship spent resins, it's just normally in a
12 shielded container. So if it was in a shielded container
13 like you would send spent resins in, they found it
14 credible that it could have been mixed in with this
15 material.

16 DR. CORRADINI: All right. Thank you.

17 MR. MAYNARD: They -- I'm not sure what was
18 going on in that time, but typically it also gets scanned
19 when it arrives at the facility.

20 DR. SPITZBERG: That's correct.

21 DR. CORRADINI: Great. Great. That's where I
22 guess I was going.

23 DR. SPITZBERG: Yes, and one of the questions
24 that frequently will come up in this scenario that we
25 might not have asked ourselves quite as intensely back

1 before 9/11 is, what if somebody wanted to make off with
2 this for the wrong reason.

3 DR. CORRADINI: Right. But Said was asking
4 that question. I guess the mass level is such that --

5 DR. SPITZBERG: Well, the mass level would not
6 be enough to make -- for strategic purposes. But if you
7 wanted to make a dirty bomb it would make -- but they were
8 able to conclude that that -- the probability of that
9 occurring was very small because of the network of
10 radiation monitors and physical security that they had on
11 the building and the spent fuel pool where this was being
12 stored. And we believe that this is also credible.

13 MR. MAYNARD: Okay. If there's no other
14 questions, thank you. And we'll move on to the next
15 presentation on safety culture.

16 DR. MALLETT: But let me add something before
17 these gentlemen leave. This is Vince Evert on the left,
18 Scott Atwater also on my left and nearer to me. He
19 and -- these two individuals, and there's another
20 individual named Ray Keller, are some of those experts we
21 want to retain. They'll probably ask me for more salary
22 after this, but they are experts in this area.

23 And I think Region IV is -- you asked what are
24 the differences, we probably have a center of excellence
25 here in this area for independent spent fuel storage

1 installations. In fact, they're doing inspections at
2 other facilities in other regions because of that
3 expertise. I just wanted to point that out.

4 MALE VOICE: Thank you.

5 MR. MAYNARD: Okay. I think you're ready for
6 Linda and Roy, with safety culture.

7 MS. SMITH: We're coming. That works. Okay.
8 This is the designed after-lunch nap. I'm just kidding.

9 What I want to do today is to go over the steps
10 that we've done and taken to implement the safety-culture
11 initiative program and effectively here. And I noticed
12 when you all got the action matrices handed to you, that
13 was just sort of a little bit on context, and I thought
14 the same amount might be helpful here.

15 So I wanted to let you know that the action
16 matrix is driven by inspection results basically. And we
17 have three different kinds of inspections, and they all
18 produce findings. And when you have a greater than
19 green -- or a greater than minor finding, then it's going
20 to have to be evaluated for significance to see how far
21 you go on the action matrix.

22 And this is also -- that same finding will be
23 evaluated to determine whether or not it's a cross cutting
24 aspect, has a cross-cutting aspect associated with it.
25 And that would then be subsequently identified for

1 substantive cross-cutting issues.

2 So simply there's a pot of inspections, they
3 produce findings, the findings get evaluated by
4 significance and go down the action matrix path, and they
5 get evaluated as whether or not they are causal factors to
6 go down the other path.

7 Okay. During the safety-culture initiative,
8 what they did was try to identify the most important
9 things for safety culture so that you would assess your
10 working conditions, or your situation to see if you had
11 implemented those things. And those are what they call
12 the safety-culture components.

13 The Commission directed the staff to enhance
14 the reactor oversight process to more fully address
15 safety culture, and the three cross-cutting areas, problem
16 identification and resolution, human performance and
17 safety-conscious work environment have long been
18 recognized as a foundation for the ROP.

19 But the safety-culture initiative identified
20 that the components of each of the cross-cutting areas
21 which need to be present for an effective safety culture
22 to exist. So they're all written in the positive, and
23 then we evaluate them in the negative.

24 In total there are 13 safety-culture
25 components, nine components were evaluated during the

1 baseline inspection, and those are the ones that are
2 listed. And there's a remaining four that happened with
3 the supplemental inspections.

4 This is just one more shot at trying to go over
5 the structure. You've got the cross-cutting areas and the
6 ROP always had human performance, and problem
7 identification resolution and safety-conscious work
8 environment. What got changed was which ones were used to
9 evaluate safety -- substantive cross-cutting issues, you
10 know, cross-cutting aspects being evaluated as groups to
11 the subsequent cross-cutting issues.

12 DR. WALLIS: But these are all components --
13 excuse me. How do you measure them?

14 MS. SMITH: We don't measure them like a
15 number, but the way --

16 DR. WALLIS: But you must have some --

17 MS. SMITH: -- that you utilize them.

18 DR. WALLIS: -- way of assessing them.

19 MS. SMITH: Yes, there is a way.

20 DR. WALLIS: Which is not a measure but it's a
21 kind of a measure, qualitative measure.

22 MS. SMITH: Yes, that's true.

23 DR. WALLIS: It's a description.

24 MS. SMITH: Yes. What --

25 DR. WALLIS: How is it done, how do you do

1 those -- how does it -- how do you know whether it's good
2 or bad or indifferent, or -- how did you give it an A, B
3 or C, or whatever you do?

4 MS. SMITH: Well, the source of these is
5 helpful to understand that answer, is that they come from
6 inspection reports and it's a greater than minor finding.
7 And so you look at the thing and you know you're not --
8 it's not supposed to happen, it's a performance
9 deficiency, it's a violation. It's not supposed to
10 happen.

11 You determine that it's greater than minor,
12 which means it's significant enough to be included in this
13 process, and then you look at your violation or
14 performance deficiency and you try to identify if these
15 issues are -- issues is a bad word -- these aspects are
16 things which would prevent you from the deficiency, or
17 cause -- it's like a cause code analysis system.

18 So these essentially work as little pre-
19 designed root cause -- common cause codes really about an
20 organization. So as you have violations and findings
21 coming in, and you assess those to see if there are any
22 safety-culture components, which are the ones that are
23 listed, that could have contributed significantly towards
24 the deficiency or the violation happening.

25 DR. APOSTOLAKIS: I think you are not really

1 assessing how well --

2 MS. SMITH: Right.

3 DR. APOSTOLAKIS: -- you're not grading or
4 rating, A, B, C.

5 MS. SMITH: Right.

6 DR. APOSTOLAKIS: If there is a violation
7 somewhere, and you suspect that it was an issue of human
8 performance, then the way I understanding it, you look
9 deeper and you say, oh, this was an issue of resources.

10 MS. SMITH: Right. Exactly.

11 DR. APOSTOLAKIS: And then the licensee I
12 guess, if they agreed with you, will have to do something
13 about it.

14 MS. SMITH: That's correct.

15 DR. APOSTOLAKIS: Because otherwise you have
16 the issue of what is a good safety culture, but nobody
17 knows what that is.

18 MS. SMITH: Right. They know the things that
19 are listed there are all good things. They figured --

20 DR. APOSTOLAKIS: Yes.

21 MS. SMITH: -- out these are the components,
22 what you want to look for and have. And it's kind of
23 go/no go, does this look like something --

24 DR. WALLIS: So you go --

25 MS. SMITH: -- that could have been caught.

1 DR. WALLIS: -- back to the licensee for their
2 assessment of how well they did on work control, or
3 whatever it was?

4 MS. SMITH: Yes. For each time we have a
5 finding that we've evaluated and we think there's an
6 aspect, there'll be dialogue with the licensees during the
7 inspections, at the pre-brief, at the exit. If they find
8 new facts it can be after the exit, after the report's
9 even been written, if it's -- we'll -- but they'd have to
10 put it on the docket.

11 But we try to get all the facts on the table
12 commensurate with the safety significance, because
13 there -- it would be the very best if we always perfectly
14 knew what the root cause were and we could perfectly --

15 DR. WALLIS: Suppose you pick the perceptions
16 fo retaliation. I mean, how do you determine something
17 like that in a fair way? Do you have to go down and ask
18 questions of individuals and --

19 MS. SMITH: Yes. Actually another piece of
20 this initiative was to add a set of questions -- they were
21 there before, but to strengthen them quite a bit -- to the
22 problem identification and resolution inspection. And
23 there's kind of two ways that sort of thing would come up.
24 One is either through the allegation process, or it will
25 come up in this safety-conscious work environment survey.

1 And so in both cases it uses slightly different
2 administrative mechanisms. We evaluate what the
3 allegation is, or the assertion is, and then we work
4 through that process to disposition it.

5 DR. APOSTOLAKIS: But, again, this is in the
6 context of a specific finding, is it not?

7 MS. SMITH: Yes. These are --

8 DR. APOSTOLAKIS: They're not going to give out
9 questionnaires asking people, you know, whether they
10 perceive that there is --

11 MS. SMITH: No.

12 DR. APOSTOLAKIS: -- an indication --

13 MS. SMITH: That's true. And --

14 DR. APOSTOLAKIS: -- a possible --

15 MS. SMITH: -- it's in the finding, aspect of
16 the finding.

17 DR. APOSTOLAKIS: In the context of the
18 finding.

19 MS. SMITH: That's right. It is also true
20 we're going to go ask those questions, but it's not in the
21 context of determining --

22 DR. APOSTOLAKIS: Right.

23 MS. SMITH: -- a cross-cutting aspect.

24 DR. APOSTOLAKIS: You are characterizing the
25 finding.

1 MS. SMITH: Right. Yes. And by doing that,
2 then once we've had one that we've characterized as a
3 legitimate cross-cutting aspect, which means it had a
4 significant contributor -- it was a significant
5 contributor to the performance deficiency, and also that
6 it reflected currently performance, because like, for
7 example, you might have some old design issue that you
8 find and it's a violation.

9 But this process is all built with the
10 assumption of trying to modify and improve current
11 performance or safety-culture things. And so you might
12 not include the design one if it was an old issue.

13 Now, if they've revised the CAP a year ago and
14 should have caught it, you know, then it would be now
15 something which is reflective of more current performance,
16 and it would still be eligible to become a cross-cutting
17 aspect.

18 MR. MAYNARD: If there's suspicion of
19 wrongdoing or intimidation, harassment, there are other
20 mechanisms --

21 MS. SMITH: Yes.

22 MR. MAYNARD: -- available to the agency. It
23 kind of tosses that into a different ball game.

24 MS. SMITH: Yes. But this -- yes, that's
25 exactly true. But we do still have the possibility, if it

1 comes out and we write a chilling-effect letter, for
2 example, because we've decided it's not isolated and the
3 licensee has something they need to worry about, that'll
4 be something -- and there's was a finding associated with
5 it, then that could be a cross-cutting aspect.

6 So we could have a SCWE cross-cutting aspect.
7 They're just a little harder to get.

8 DR. MALLETT: The issue I talked about this
9 morning the licensees are raising is they wanted more
10 definition because prior to this we'd say, well, we have a
11 human performance issue, and they'd say, well, how did you
12 decide that. And it might be I might have one way, Linda
13 my have another one, Roy may have another one. So we
14 said, well, let's put some, what did you call them,
15 components down there, or attributes that we said we could
16 use.

17 So we gave these to the inspectors. I'm just
18 trying to make a point here. So what happens now, the
19 inspection makes a finding, and they he says, does it have
20 an aspect of one of these sub-components. Yes, it does;
21 I'll put into that bin. The licensees' argument is,
22 there's no threshold.

23 You've told him he has to find a spot to put
24 it.

25 DR. WALLIS: There's no measure.

1 DR. MALLET: There's no --

2 DR. WALLIS: There's no --

3 DR. MALLET: -- as you indicated --

4 DR. WALLIS: Right.

5 DR. MALLET: -- no threshold amount. So that
6 is an issue. I hope that helps.

7 DR. WALLIS: So how do you know when it's been
8 corrected?

9 DR. BONACA: It has to be more than minor?

10 MS. SMITH: Yes, there is a threshold.

11 MR. CANIANO: There's a threshold.

12 DR. BONACA: And how do you define that?

13 MS. SMITH: At the risk of getting into big
14 trouble.

15 DR. BONACA: Again, is it a vague definition,
16 or is it a tangible definition, something that --

17 MS. SMITH: Yes. That is --

18 DR. BONACA: It does.

19 MS. SMITH: Yes. It has to be a more-than-
20 minor finding.

21 DR. BONACA: You have some guidance.

22 MR. CANIANO: There is criteria.

23 DR. BONACA: Yes, there is some criteria.

24 MR. CANIANO: There definitely is criteria.

25 It's in our manual chapter that defines minor violation.

1 When you identify an issue where does it fall into, is it
2 minor, is it something that's non-cited violation, and
3 there, there is specific criteria.

4 MS. SMITH: Okay. So just to recap quickly.
5 The original cross-cutting areas are human performance,
6 PI&R and SCWE, and they're comprised -- those are the nine
7 safety-culture components. And you can see how they
8 distribute themselves among the cross-cutting areas.

9 In the implementation challenges of this phase,
10 though, there's been improvement in Region IV. One of the
11 things that made it better was the manual chapter 03.05
12 clearly lists all the components and their definitions.
13 That's what we were talking about. And it even has
14 developed a cause code numbering system for evaluating the
15 cross-cutting aspects, and this aids in communication.

16 And then the thing that I think has been the
17 most effective actually has been the management review of
18 the -- during the morning meetings, during morning
19 meetings you've heard talked about before. One thing we
20 use those meetings for is to go over the enforcement
21 that's being proposed and the findings for all of the
22 inspection reports.

23 And we've had real strong management presence
24 during -- when these were first being worked on to make
25 sure that everybody was doing them the same way.

1 DR. ABDEL-KAHLIK: Do you try to correlate the
2 outcome of different findings just to see, even though
3 these might be qualitative, that there may be sort of a
4 persistent trend?

5 MS. SMITH: Well, we're looking for a
6 persistent trend. And if you have the cross-cutting
7 aspect -- say you have a performance deficiency; you've
8 decided that one of those things is a contributing cause
9 to it and you think it's a current performance -- then
10 that goes in your bucket that you start doing the bin in,
11 and you sort them by themes to try to find the theme.

12 And then once you get greater than three, you
13 say, okay, I've got a theme, and then you get into the
14 substantive cross-cutting issue. And so the outcome is
15 really a trend analysis.

16 DR. ABDEL-KAHLIK: Okay.

17 MS. SMITH: Common cross-trend analysis.

18 DR. BONACA: The big difference now is that you
19 can trigger a self-assessment based on the three more-
20 than-minor findings in a specific area. That's a
21 difference from the system before?

22 MS. SMITH: The -- yes, the substantive cross-
23 cutting issues before didn't used to have as many bins
24 as -- now they've got nine; they used to have five or six.
25 And they didn't have safety-conscious work environment

1 before.

2 And so what they did with the safety-culture
3 initiative was make the bins more comprehensive of the
4 things that you're going to see, and add things to look at
5 for safety-conscious work environment.

6 DR. APOSTOLAKIS: Are the words "safety
7 culture" anywhere in the --

8 MS. SMITH: Yes.

9 DR. APOSTOLAKIS: -- documents?

10 MS. SMITH: They don't talk about -- the part
11 that I'm talking about now is safety culture directly.

12 DR. APOSTOLAKIS: Right.

13 MS. SMITH: They talk about the supplemental
14 inspection stuff, which I'm going to get to.

15 DR. APOSTOLAKIS: Because I know the Commission
16 was -- especially the chairman -- didn't like those words.

17 MS. SMITH: Well, and what they're saying is
18 part of it is just kind of like routine work, in the
19 routine work they're going to use the components, safety-
20 culture components.

21 DR. APOSTOLAKIS: So we're using components --

22 MS. SMITH: Yes. This is --

23 DR. APOSTOLAKIS: -- when we're talking
24 about --

25 MS. SMITH: -- the routine --

1 DR. APOSTOLAKIS: -- culture.

2 MS. SMITH: This is -- they call them cross-
3 cutting area components. That's for the nine. But when
4 they add the --

5 DR. APOSTOLAKIS: When you have a culture --

6 MS. SMITH: -- four more -- there's four more,
7 and which I'll get to, and then they say safety culture,
8 and they talk about safety-culture assessments.

9 DR. APOSTOLAKIS: Oh, they do comply by this.

10 MS. SMITH: Yes. Later on. Okay. Now, this
11 is just to kind of show you -- I'd said in manual chapter
12 03.05, it laid out the terms. So for safety-conscious
13 work environment, that cross-cutting area you could have
14 an environment for raising concerns, which would be called
15 a cross-cutting component, and it's paragraph S.1(a).

16 So if you look through the manual, you could
17 find that paragraph number, and it would discuss behaviors
18 and interactions that encourage free flow of information
19 related to nuclear safety issues, differing professional
20 opinions, and identifying issues and the corrective action
21 program and through self-assessment, and that's your
22 cross-cutting aspect.

23 So the next part is what -- really what we
24 talked about already, the going through the analysis of
25 your cross-cutting aspects. And basically licensees

1 often don't do full root cause analysis, so you've decided
2 something's a significant contributor, but actually you
3 probably don't know in the same way you would know if
4 someone had done a root cause analysis.

5 But we just kind of had to come to grips with
6 using the available information the best we could to
7 evaluate safety-culture things. And so that's what
8 happens. That's been a little hard for the inspectors to
9 deal with because they like things done perfect. But
10 we're working on it.

11 And as a result of continued management focus
12 and feedback from the stakeholders, documentation and the
13 basis for identifying a substantive cross-cutting issue
14 and an assessment letter has also been approved.

15 Now, here you take that group of four or five
16 or ten substantive cross-cutting aspects that have the
17 same themed -- or cross-cutting aspects that have the same
18 theme, and you propose a substantive cross-cutting issue,
19 and you would do that if you were -- you believed that --
20 you didn't think -- you didn't confidence that the
21 licensee would fix it. This is the place --

22 MR. CANIANO: This is place --

23 MS. SMITH: -- where the confidence --

24 MR. CANIANO: -- where the criteria --

25 MS. SMITH: -- comes in.

1 MR. CANIANO: -- is that we talked about.

2 DR. APOSTOLAKIS: So a weak aspect becomes an
3 issue, is that what it is?

4 MS. SMITH: Yes, if you clump together the
5 aspects --

6 DR. APOSTOLAKIS: Or maybe than one aspect?

7 MS. SMITH: Yes, you have to have greater --

8 DR. APOSTOLAKIS: Yes.

9 MS. SMITH: -- than three. But practically
10 speaking we usually look for more than that. We look for,
11 you know, a good solid trend. And --

12 DR. APOSTOLAKIS: You made that a three?

13 MS. SMITH: Number -- the number three. So if
14 I have three findings, and the period is the six months of
15 the assessment plus the six months before that, so you
16 look back for a 24 month period together. And if they
17 had -- for the aspect we were talking about before, which
18 was the cross-cutting aspect on environment for raising
19 concerns, if -- well, that's not a good idea --

20 DR. APOSTOLAKIS: If they are sleeping in the
21 control room --

22 MS. SMITH: Yes.

23 DR. APOSTOLAKIS: -- we have to catch them
24 three times, or --

25 MS. SMITH: Oh.

1 MR. CANIANO: No.

2 MS. SMITH: No, but that would be like --

3 DR. APOSTOLAKIS: What is this, a --

4 MS. SMITH: -- event driven --

5 DR. APOSTOLAKIS: -- component, an aspect, what
6 is it, can you tell me? Suppose you catch them asleep.

7 MS. SMITH: That's the finding. The
8 performance deficiency is he's sleeping. But then you've
9 got to say, well, what caused him to be sleeping, what on
10 that list.

11 DR. APOSTOLAKIS: That's probably serious
12 enough.

13 MR. CANIANO: That's just an example, we go
14 well beyond this.

15 DR. APOSTOLAKIS: So -- I'm sorry.

16 MR. CANIANO: That specific example --

17 DR. APOSTOLAKIS: But why? Why? I'm trying to
18 understand --

19 MS. SMITH: When I said in the beginning --

20 DR. APOSTOLAKIS: -- is there something else
21 where you can put it in --

22 MS. SMITH: Yes. Yes. Well, there's a lot of
23 things, but the three inspection types that we have, you
24 know, one would be the -- is the event driven one that
25 responds to events and things like -- to make sure they're

1 handling it, and it can be a special inspection, an AIT,
2 an IIT --

3 DR. APOSTOLAKIS: But this is the mechanics of
4 it.

5 MS. SMITH: Yes. And those are all --

6 DR. APOSTOLAKIS: They are sleeping. That to
7 me would be a human performance issue.

8 MS. SMITH: Yes.

9 MR. MAYNARD: Well, there's a big difference
10 between one isolated case, and if you have that plus you
11 find other evidence of other things going on.

12 DR. APOSTOLAKIS: But this is so important.

13 MR. MAYNARD: But there's a way to handle the
14 single significant activity there.

15 MR. GODY: Right. If operators are sleeping
16 the control room, operators are governed by 10 C.F.R. Part
17 55. Each operator has their own license, they're held to
18 high standards, and they would be dealt with under the
19 enforcement policy. So there's --

20 DR. APOSTOLAKIS: In the action matrix, where
21 does that go? Is that a degraded cornerstone there, or
22 what?

23 MR. GODY: Well, it's -- the initial actions
24 are dealt under the traditional enforcement policy.
25 Whether or not there's other aspects, I'll let Linda talk

1 about that --

2 DR. APOSTOLAKIS: Okay.

3 MR. GODY: -- and how we would deal with those
4 other aspects.

5 DR. APOSTOLAKIS: I guess the --

6 MS. SMITH: Are you really asking --

7 DR. APOSTOLAKIS: The question, it's an honest
8 question --

9 MS. SMITH: Okay.

10 DR. APOSTOLAKIS: -- nothing else.

11 MS. SMITH: No tricks.

12 DR. APOSTOLAKIS: How do issues related to
13 human performance enter the action matrix?

14 MS. SMITH: Well --

15 DR. APOSTOLAKIS: Because it's a cross-cutting
16 issue.

17 MS. SMITH: -- that's --

18 DR. APOSTOLAKIS: It affects a lot of things.

19 MS. SMITH: That's why when I started I thought
20 maybe we needed some context information, is the action
21 matrix deals with the significance of findings. And if
22 the finding is evaluated during our significance
23 determination process to be green, you'll be in that first
24 column. If it's white you go --

25 DR. APOSTOLAKIS: Oh, okay.

1 MS. SMITH: And that's only significance.

2 But --

3 DR. APOSTOLAKIS: So then I would go to --

4 MS. SMITH: -- the other side --

5 DR. APOSTOLAKIS: -- the PRA -- assume that the
6 operators are sleeping --

7 MS. SMITH: Yes.

8 DR. APOSTOLAKIS: -- I can see how that affects
9 the core damage frequency.

10 MS. SMITH: Well, I have never done any --

11 DR. APOSTOLAKIS: And that would give me --

12 MS. SMITH: -- in that column.

13 DR. APOSTOLAKIS: -- probably a yellow or a
14 red.

15 MR. BONNETT: But there is a bigger issue that
16 says that --

17 MR. GODY: Now, hold on. I'm going to give the
18 microphone to Paul Bonnett.

19 MR. BONNETT: Hi, this is Paul Bonnett. We --
20 in response to your question about the human performance
21 and fitness for duty type of situations, thinking
22 operators, if there was a sleeping operator situation that
23 was found, we could assess that in the performance
24 deficiency.

25 That performance deficiency, if it went to an

1 SDP situation, would be looked at under the SPAR-H model
2 looking at human error probability. Now, that by itself
3 would probably come out to be of very low significance
4 because an operator sleeping, one operator sleeping -- if
5 you have a whole control room sleeping, you've got a
6 different issue.

7 DR. APOSTOLAKIS: But that's the whole issue,
8 it seems to me.

9 MR. BONNETT: We have a Peach Bottom issue
10 where everybody's asleep in the control room, that
11 would -- we would go first of all into our 612 appendix B,
12 which -- where we identify the performance deficiency,
13 then ask does this fall under traditional enforcement. If
14 it goes under traditional enforcement, it will go over and
15 look at the actual consequences, potential consequences,
16 if it was willful, or it impeded the regulatory process.

17 At that point, once we looked at the violation,
18 we could do the significance determination to find out
19 what the safety significance of that violation was, and
20 then tag a color significance to that violation.

21 DR. APOSTOLAKIS: So traditional enforcement
22 takes precedence over the matrix.

23 MR. BONNETT: Yes. Yes. As you would go down
24 the list, we do the tradition, then we go down to find out
25 whether or not it goes through the SDP.

1 MS. SMITH: But it -- okay.

2 DR. MALLETT: Traditional enforcement does not
3 take precedence. It -- there are two pathways. Some of
4 the pathways in the reactor oversight process do not have
5 a significance determination process connected with them.
6 And so we handle those by the traditional method of
7 enforcement, which has a scale of examples in it that were
8 based on safety significance at one point in time.

9 DR. APOSTOLAKIS: No, but you have --

10 DR. MALLETT: But it's not that one takes
11 precedence over the other.

12 DR. APOSTOLAKIS: But you --

13 DR. MALLETT: It's just another way of --

14 MR. MAYNARD: Well, everything gets dealt with
15 in both systems.

16 DR. MALLETT: Right.

17 MR. MAYNARD: Every finding has to be dealt
18 with in the traditional system as far as is it -- what's
19 the significance of it and, you know --

20 DR. MALLETT: Well, we've created these terms.
21 These terms that we've created are the reactor oversight
22 process, we went down the path of significance
23 determination, evaluations of findings. But some findings
24 either don't lend themselves to that, and we haven't
25 developed a technique for that, so we have said, okay, in

1 those cases we will handle those by the old way; we used
2 to do finding evaluations, and we call that tradition.

3 It's not that everything's held that way; it's
4 just if you don't have an SDP for evaluating it, you go
5 the other route. And in this case of operator licensees
6 sleeping in the control room, there's no SDP evaluation in
7 the ROP, so you go this other way of evaluating that.

8 DR. APOSTOLAKIS: But you could --

9 DR. MALLETT: Yes, you could.

10 MR. GODY: Yes, can I build on that just a
11 little bit? If we were to deal with an operator licensing
12 issue, and it was an individual and it was truly an
13 individual case, we would deal with it as an individual
14 case under the enforcement policy.

15 We did have one licensee in this region that
16 had a series of fitness-for-duty events at their facility.
17 And we processed each one of those fitness-for-duty issues
18 with -- individually by operators. But at a certain point
19 it triggered some concern on our part that there might be
20 some programmatic issues, so we wrote them a letter and
21 asked them to describe it.

22 Now, ultimately we determined that they didn't
23 have a programmatic issue. But had they -- had we
24 determined that they had a programmatic issue, then we
25 would have dealt with that within the confines of the

1 reactor oversight process and significance determination
2 process.

3 And we have had some examples where we have had
4 individual operator issues that we've attributed to the
5 licensee because it was a programmatic licensee issue.

6 DR. MALLET: Let me add to that. What happens
7 then is during the mid-cycle or the end of cycle
8 assessment that we talked about earlier, we'll talk about
9 those -- Tony and his staff come to that and we'll talk
10 about what operator, or examiner issues they found, or
11 issues during the re-qual inspections, and how does that
12 factor into the reactor oversight process.

13 But we may use that as an example to say, well,
14 we think we have a substantive cross-cutting issue, here's
15 another example of that. If that makes sense.

16 MS. SMITH: Yes. So you just --

17 DR. APOSTOLAKIS: But --

18 MS. SMITH: I'm sorry. Well, you just -- what
19 they've been describing is you've got the finding, you
20 disposition it in enforcement and significance space, then
21 you end up with a finding you know is greater than green.
22 And then you can look at that finding to see whether it is
23 a contributing cause -- it was a contributing cause to it,
24 whether it was a cross-cutting aspect.

25 And then that could add to your theme. Maybe

1 you've had worker practice problems in maintenance and
2 operations. Together those make a theme.

3 DR. APOSTOLAKIS: I guess my -- what's not
4 clear to me is do all findings go to the action matrix?

5 MS. SMITH: Yes. Once they're -- if they're
6 finding a performance -- if they turn out to be a
7 performance deficiency, then they would be evaluated to
8 what you would do with an action matrix. If they're
9 green, it doesn't really tell you to do anything.

10 DR. APOSTOLAKIS: No, no, no, put more
11 important things like -- but certain things, like operator
12 performance, there are special rules about those things.

13 MS. SMITH: Right.

14 DR. APOSTOLAKIS: So I have now -- I can do an
15 SDP and say, you know, that this guy was sleeping, how
16 does that affect CPF. At the same time, I have the
17 requirements which tell me that, boy, this guy's not
18 supposed to be sleeping, so you've got, you know, to
19 penalize in some way.

20 So I really don't -- do I need to do an SDP in
21 that case, if there is already a regulation?

22 MR. BONNETT: Let me add something to that.

23 DR. APOSTOLAKIS: Yes.

24 MR. BONNETT: If there was a sleeping operator
25 or an inattentive operator, what would happen -- what we

1 do is we would look to see if there was performance
2 deficiency. Was there a condition that was created that
3 would have led to a core damage situation.

4 At that point we would assess the performance
5 deficiency. In that performance deficiency we would look
6 to see to see what kind of causal factor there was in that
7 finding, which, in this case, it was a sleeping operator,
8 if he was in direct correlation, that would have come in
9 as a cross-cutting issue.

10 If there was greater than three number of
11 common theme cross-cutting issues, that would to in to be
12 assessed under the safety culture, and it would come out
13 in that sort of assessment.

14 As we assess the performance deficiency, one of
15 the things that we look at in that is the human
16 performance area, which drilled way down in that
17 assessment is fitness for duty, and that's part of the
18 human error probability. But that's only one of eight
19 criteria that we look at in that SPAR-H model.

20 MR. MAYNARD: What I'd like to suggest, we have
21 some time at the end for roundtable discussion, opened up
22 to anything. We are falling further behind. I'd like to
23 go ahead and suggest we move ahead and then maybe come
24 back and have some roundtable discussion.

25 MS. SMITH: Well, you had mentioned that you

1 were interested in, when they use safety culture,
2 there's -- the ways that the program now allows us to ask
3 for the licensees to do safety-culture assessments that
4 are new.

5 DR. APOSTOLAKIS: That's right. That's what I
6 asked --

7 MALE VOICE: What?

8 MS. SMITH: Pardon?

9 DR. APOSTOLAKIS: Yes, that's what I asked
10 before.

11 MS. SMITH: Yes. Okay. And there they are.

12 And then the biggest challenge for this -- in
13 implementing this program is complex terminology because
14 you just have to say "aspect" the right time and "area"
15 the right time or you get confused, and that has happened
16 at the inspection staff level, too, and so we have to work
17 hard to overcome that.

18 DR. APOSTOLAKIS: Well, again -- I'm sorry,
19 Otto, but these things about culture are there to help the
20 agency and the licensee identify root causes that are
21 organizationally related or human related, but they are
22 not things that go into the matrix. The matrix looks only
23 at the performance.

24 MS. SMITH: Significance.

25 DR. APOSTOLAKIS: Significance.

1 MS. SMITH: Yes.

2 DR. APOSTOLAKIS: But -- and there has to be a
3 real finding, some condition for you to go to the matrix.

4 MS. SMITH: Yes.

5 DR. APOSTOLAKIS: The fact that they didn't
6 have enough stuff doesn't go to the matrix; is possibly
7 one of the root causes that created the finding. Is that
8 correct?

9 MS. SMITH: It is correct.

10 DR. APOSTOLAKIS: That makes is much clearer in
11 my mind now.

12 MS. SMITH: Yes, the only slight --

13 DR. APOSTOLAKIS: It should have been clear
14 before --

15 MS. SMITH: -- variation is the cross-
16 cutting --

17 DR. APOSTOLAKIS: -- I think.

18 MS. SMITH: -- aspect also could start from a
19 performance deficiency, but it's about causes.

20 DR. APOSTOLAKIS: It's causes.

21 MS. SMITH: The matrix is about significance.

22 DR. APOSTOLAKIS: Performance. It's
23 performance, the safety assessment.

24 MS. SMITH: Significance.

25 DR. APOSTOLAKIS: Yes --

1 MS. SMITH: Yes.

2 DR. APOSTOLAKIS: -- significance.

3 DR. MALLETT: In order to move on, when we get
4 to the roundtable, we have an example that occurred here,
5 and we can mention this because it's a public -- at the
6 River Bend Station, it was an operator, and we can go
7 through that. That might help you as an example, how that
8 played out.

9 DR. APOSTOLAKIS: Thank you. Good.

10 MS. SMITH: But then -- and this is towards the
11 end -- because of it being a hard concept to just learn to
12 talk about and be able to exchange on, we had several
13 training sessions, and the counterpart meetings; we've
14 provided web-based training for anyone.

15 And we also -- I mentioned that increase of
16 management oversight over the inspection finding
17 disposition, making sure everybody was thinking everything
18 the same thing. We had meetings to train the security
19 community, and we hosted a regional utility group meeting,
20 so that when you're talking to the licensee everybody was
21 together.

22 And we also have kind of planned, and it's been
23 there sort of from the beginning, that the ROP annual
24 self-assessment report would look at this. And then
25 another sub-tier to that is the 18-month safety-culture

1 self-assessment group, and the routine procedure in review
2 and upgrades, these procedures have been revised several
3 times to clarify them.

4 And the manual chapter 6.12 working group,
5 they're performing a deficiencies cross-cutting aspect
6 audit, and two or three of these feed into the -- besides
7 being at the regional level, they're national.

8 And what Roy Caniano is going to do now is to
9 talk about the effort he's on.

10 DR. BONACA: I have a question on 95003.

11 MS. SMITH: Okay.

12 DR. BONACA: I mean, the way it's been
13 developed, now it's much more precise and descriptive
14 about what you're expecting --

15 MS. SMITH: Right.

16 DR. BONACA: -- in this evaluation. And how do
17 you trigger this evaluation? That was the question I had
18 before. It seems to me that --

19 MS. SMITH: The 95003?

20 DR. BONACA: Yes.

21 MS. SMITH: The way you trigger one of those is
22 back over on the action matrix, if you have enough
23 significant performance deficiencies, as those increase in
24 significance, they have you -- and you go across the
25 columns, and 95003 is required when you're in that last

1 column.

2 MALE VOICE: Second to the last.

3 MS. SMITH: Second to the last.

4 DR. BONACA: Second to the last.

5 MS. SMITH: Right.

6 DR. BONACA: Okay.

7 MS. SMITH: So it's by significance. But then
8 it goes into culture in that what it tells you to do is to
9 evaluate -- they'll have the licensees do a safety-culture
10 assessment.

11 DR. BONACA: But it seems to me that 95001
12 already allows now the stuff to trigger a self-assessment
13 if there are three -- more than three known minor
14 events --

15 MS. SMITH: Yes.

16 DR. BONACA: -- in the same category, which
17 means before you can --

18 MS. SMITH: No, more than three assessment
19 letters.

20 DR. BONACA: What? Yes.

21 MS. SMITH: I'm sorry.

22 DR. BONACA: An assessment of performance.

23 Right?

24 MS. SMITH: Yes.

25 DR. BONACA: And it would expect that that

1 assessment to performance would be similar in many ways to
2 if a contractor would do it for the licensee. I would
3 expect it to be very similar to 95003, because now you
4 have specified there what you expect to see.

5 MS. SMITH: There would be some similarities.
6 Do you want to talk about that --

7 MR. WERNER: Well, from a --

8 DR. APOSTOLAKIS: No, you have to --

9 MR. WERNER: This is Greg Werner.

10 MS. SMITH: He's working on the 95003.

11 MR. WERNER: Yes, I'm the senior projects
12 engineer for Palo Verde. I'm familiar with the 95003. As
13 assistant team leader of the 95003, I have responsibility
14 for the safety-culture aspect.

15 So, again, it's just a graded approach, again,
16 the ROP, so the 95001 would not have as significant of a
17 review for safety culture as the 95003 would, because,
18 again, that's the first starting point. So, again, as the
19 findings become more significant, the amount of effort by
20 both the NRC and the utilities are going to increase at
21 each stage.

22 So, again, it would not be a significant --
23 again, the 95003 has approximately 450 hours of direct
24 inspection that was added for safety culture alone.

25 DR. BONACA: The 95001 would be on the same

1 issues, but it would be not as in depth.

2 MS. SMITH: Right.

3 MR. WERNER: Right. That is correct. Again,
4 you have to look at the 95001 specifically, but, again,
5 that's usually just looking at the one aspect of
6 performance that got you in that area. So you have a
7 cornerstone; it's not going to be nearly as in depth.

8 MS. SMITH: And that matches what causes it
9 because like a white one makes a 95001, and then you've
10 got white ones or a yellow to get to 95002, like that. So
11 as the significance of the event or deficiency increases,
12 you go further out on the action matrix.

13 And then if the safety -- substantive cross-
14 cutting issue recurs for three times, then we can write an
15 assessment letter to the licensee asking them to perform
16 one of those assessments.

17 And that's all I have. Thank you.

18 MR. CANIANO: And thank you, Linda.

19 Again, I'm Roy Caniano. I'm the deputy
20 director of the Division of Reactor Safety here in the
21 Region IV office.

22 Earlier today, Bruce, I think in his opening
23 remarks, mentioned that we were initiating a review of the
24 region's implementation of cross-cutting aspects. I think
25 also Pat mentioned this morning that, you know, the agency

1 and the region is -- we're a learning organization.

2 So what prompted us to take a look at this?
3 When you take a look at the total number of findings
4 across the agency, and how many of those findings have
5 cross-cutting aspects with it, there's a difference
6 between the regions.

7 For example, 2006 Region IV had 218 inspection
8 findings. Of the 218 findings, we had 179 that were
9 tagged with a cross-cutting aspect. Now, if you compare
10 that to some of the other regions, there's a delta.
11 Region III, for example, has 242 findings with 116 cross-
12 cutting aspects associated with it. In Region II we had a
13 136 findings with 68 cross-cutting aspects. Region I you
14 had 182 findings with 143.

15 DR. APOSTOLAKIS: You have X with Y relating to
16 components. That's what you mean.

17 MR. CANIANO: Yes.

18 DR. APOSTOLAKIS: Okay.

19 MR. CANIANO: Yes.

20 DR. APOSTOLAKIS: So you're not talking about
21 the number of aspects?

22 MR. CANIANO: Yes. We looked at it and we
23 said, you know, why is that. So we decided on a
24 initiative that we were going to initiate a cross-cutting
25 task group, which I'm leading. We kicked it off about

1 three months ago.

2 The whole purpose is to identify the
3 differences and/or similarities among the regions, how we
4 implement 03.05 which is the guidance documents, et cetera
5 for cross-cutting aspects. We're very fortunate because
6 we've got numbers from each of the regions. I represent
7 Region IV. We also have the office of enforcement, as
8 well as NRR represented on this task group.

9 Now, early phase of this, we found that there
10 were two other task groups that are out there that are
11 reviewing inspection reports, 06.12, which is the format
12 for inspection reports, there's a task group that's
13 reviewing inspection reports to make sure that the reports
14 are consistent with the requirements of 06.12.

15 At the same time there's a problem
16 identification and resolution task group that also is
17 looking at inspection reports. What we did not want to do
18 is duplicate their efforts. So we got with those two
19 groups and we basically discussed with them what do we
20 want out of this task group.

21 And they are looking at about 60 plus
22 inspection reports throughout all of the regions. We go
23 back to about the October time frame, we're looking at the
24 resident inspector inspection reports, and we're looking
25 also at the division of reactor safety inspection reports,

1 which, of course, has the regional based inspection
2 reports.

3 We're also taking a look at statistics. The
4 statistics I have you earlier were some of the NRC
5 statistics. Last week I had the opportunity to
6 participate in the annual American Nuclear Society
7 meeting, and I had an opportunity to talk to them about
8 our task group.

9 And I solicited input from them as well, you
10 know, what type of data do you have that are out -- that's
11 out there, and do you have any specific concerns with the
12 way that the agency is implementing cross-cutting aspects.
13 And actually at the end of September they've invited me to
14 participate in another forum to where they're going to be
15 able to communicate with me any specific findings that
16 they have.

17 In addition to that, what we're also doing is
18 we're participating, the task group members, in the mid-
19 cycle reviews and in the inspection de-briefs. We
20 mentioned earlier that Region IV had their mid-cycle
21 reviews last week. We actually had the task group member
22 from Region I participate in that effort.

23 Again, to get a sense what type of questions
24 are we asking when a finding is identified. We want to
25 make sure that we're consistent when their questioning the

1 attitude, as well as the guidance in 03.05, how do you tab
2 a finding with the cross-cutting aspect.

3 Tomorrow I'm going to be involved, in fact, in
4 Region I mid-cycle. And, again, to get an assessment of
5 how that region does it. Region III is going to be going
6 to Region II and vice versa, Region II going to Region
7 III. In addition to that, we're also talking to the
8 inspectors, we're talking to the supervisors, and, again,
9 hat's to get a sense on how are the regions implementing
10 the cross-cutting aspects.

11 Our goal is to have this completed by the end
12 of this calendar year. A big reason for that is we wanted
13 some changes that are going to be necessary. We want to
14 make sure that we can get them in before the next
15 inspection cycle.

16 So it's a rather large effort, and, again, I
17 think by involving and seeking input from utilities, I
18 think is going to be very valuable. Again, by the end of
19 September I'm hoping that I can get some useful
20 information from them.

21 MR. MAYNARD: Okay. Appreciate it.

22 MR. CANIANO: Okay.

23 MR. MAYNARD: Thank you very much. I think
24 next on our agenda, component design basis inspections,
25 and I believe that's George Replogle.

1 MR. GODY: Yes, sir. Let me introduce George
2 Replogle. He's a senior project engineer in the Division
3 of Reactor Projects, and he will be talking about our
4 component design basis inspection program.

5 MR. REPLOGLE: How are you all doing? I'm
6 George; I'm a public servant. I'm glad to be able to sit
7 here and talk with you today.

8 To be honest, I'm not really involved in these
9 inspections that much anymore. I had led a few, but when
10 the other folks found out you were coming, they took trips
11 out of town. So here I am.

12 MR. MAYNARD: I notice you do have several
13 slides, and --

14 MR. REPLOGLE: Yes, sir.

15 MR. MAYNARD: -- we appreciate moving
16 through -- try to catch the key points here. I don't want
17 to cut you short, but actually I am trying to move it
18 along a little bit here.

19 MR. REPLOGLE: Yes, I will go as fast as I
20 possibly can.

21 MR. MAYNARD: And I realize we're usually the
22 speed bump.

23 MR. REPLOGLE: The component design basis
24 inspections are the latest version of the NRC's team
25 inspections. We have had some trial inspections in 2005,

1 and these inspections have a reasonably big team, six
2 members including the two contractors and one operations
3 examiner.

4 The team spends three weeks on site. A team
5 leader and the senior reactor analyst will also spend an
6 additional week.

7 And we have a risk-informed scope. We look at
8 20 risk-important role margin components, five risk
9 important operating experience issues, and that's a little
10 bit misleading, because for the 20 components, we're going
11 to look at over 100 operating experience reports. For
12 the -- the five additional allows us to step outside that
13 scope and look at other OEs. And then five risk-important
14 operator actions.

15 The teams spends about a third of the allotted
16 time just picking out what we're going to look at. And
17 that's sort of a funny way to do things, but we believe
18 that we're going to pay up front and we'll get dividends
19 later. And I think it's been really working out. We've
20 been getting a lot of fruit from our efforts, and it seems
21 like a good way to do things for now.

22 Nationwide, the CDBIs in the last year and a
23 half or so have generated 136 findings, one white finding
24 vortexing issue at Clinton, Region III. And Region IV,
25 out of those, has 24.

1 And in short my goal on these inspections was
2 to find latent design issues. Not everything that
3 happened at TMI was risk significant. There were a number
4 of ducks that had to line up in a row to get to core
5 damage, and if you could have taken one of those ducks
6 out, even a non-risk-significant duck, and just pulled it
7 out, you wouldn't have had core damage.

8 So although we're finding mostly green
9 findings, that we're helping safety and we're taking some
10 of those pieces out that can lead to core damage.

11 DR. CORRADINI: So just -- I keep on assuming,
12 so when you say a green finding, that's something that's
13 not of safety significance, but of concern that needs to
14 be dealt with.

15 MR. REPLOGLE: That's correct.

16 DR. CORRADINI: Is that essentially the proper
17 way of thinking about it?

18 MR. REPLOGLE: That's correct.

19 DR. APOSTOLAKIS: Green means two things: In
20 performance indicators it means nothing happened.

21 MR. REPLOGLE: That's correct.

22 DR. APOSTOLAKIS: In the findings it means
23 something has happened --

24 MR. REPLOGLE: So that's why --

25 DR. APOSTOLAKIS: -- but it has very low

1 significance.

2 DR. CORRADINI: So it's a concern, not a
3 deficiency or a weakness.

4 DR. APOSTOLAKIS: Huh?

5 DR. CORRADINI: I view it -- I interpret it,
6 when you say the green finding, it's something you noted,
7 should be discussed, taken care of, but it's not of safety
8 significance that would start adding up to --

9 MR. GODY: A green finding, clearly they did
10 not implement an industry standard, or they didn't meet a
11 requirement, so there is either a violation or they failed
12 to implement a standard.

13 What we do is we assess the significance of
14 that issue and we determine that it is of very low safety
15 significance --

16 DR. CORRADINI: Therefore green.

17 MR. GODY: -- and that's -- and therefore
18 green.

19 MR. REPLOGLE: These are greater than minor, so
20 these are documented in reports, but we don't have
21 additional enforcement actions that follow.

22 DR. APOSTOLAKIS: If an inspection finds that
23 everything is fine, there is no color.

24 MR. REPLOGLE: That's correct.

25 MR. GODY: And green finds --

1 DR. APOSTOLAKIS: There is a color to --

2 MALE VOICE: No finding.

3 MR. REPLOGLE: That is correct. And all --

4 MALE VOICE: There's no findings.

5 MR. REPLOGLE: -- findings --

6 DR. APOSTOLAKIS: There are no findings. Yes.

7 That's the word.

8 DR. BONACA: If you find a component that is

9 not operable but it's well functional.

10 DR. APOSTOLAKIS: But this thing about the --

11 DR. CORRADINI: I don't mean to bring this up,
12 but I just -- you were using these terms, and I know about
13 from a performance indicator standpoint, but I just want
14 to make sure I understand --

15 MALE VOICE: Wait, wait.

16 MR. MAYNARD: We need to -- one at a time here.

17 Let --

18 MR. GODY: Yes.

19 MR. MAYNARD: -- Mario ask his question.

20 MR. GODY: There was a couple of questions
21 here.

22 Dr. Bonaca, you said if it's operable but
23 functional -- I mean, if it's not operable but functional.
24 If it's not operable, it means it doesn't meet a tech spec
25 requirement, and if there's a performance deficiency

1 associated with it, then there's a finding, and we assign
2 a significance to it.

3 There was another question. Any findings that
4 are raised by inspectors, are we -- we expect them to put
5 those issues in the corrective action program and fix.

6 Were there any other questions?

7 MR. REPLOGLE: You could have instances where
8 equipment is inoperable and it would still be a green
9 finding. For example, the large-break loss-of-coolant
10 accidents, the frequency of those occurring, we believe,
11 is so low, the equipment is only needed to mitigate a
12 large-break loss-of-coolant accident; the risk would still
13 be green. So you can have pretty significant issues that
14 are still greenish.

15 DR. BONACA: Just in function.

16 MR. REPLOGLE: It could be inoperable.

17 DR. BONACA: But in our inoperable and non-
18 functional is two different things. I mean, you may not
19 meet the code, but you may determine that the component is
20 capable of performing this function.

21 MR. REPLOGLE: It could be inoperable and non-
22 functional.

23 DR. BONACA: Even in that case it would --

24 MR. REPLOGLE: But it could still be green.

25 DR. APOSTOLAKIS: But that I believe creates an

1 issue of inconsistency of the policy. For events that do
2 appear in the PRA and events that don't function, and
3 that aren't there some findings which you cannot process
4 through a PRA. Is that not correct?

5 MR. REPLOGLE: Well, there are some, but a
6 large-break loss-of-coolant accident --

7 DR. APOSTOLAKIS: I understand.

8 MR. REPLOGLE: -- could be processed in the
9 PRA.

10 DR. APOSTOLAKIS: That's absolutely --

11 DR. SHACK: That's typically why you find so
12 many white findings in emergency planning.

13 MR. REPLOGLE: Right. That's correct.

14 DR. SHACK: And, you know, they're not
15 processed through the -- because there you're sort of --
16 you're either -- you fail or you don't.

17 MR. REPLOGLE: You make it or you don't and you
18 have a hard time assessing safety significance.

19 DR. SHACK: So there is a certain inconsistency
20 there.

21 DR. APOSTOLAKIS: Oh, this is interesting. Can
22 you go on?

23 MR. REPLOGLE: I agree.

24 DR. APOSTOLAKIS: Are all the findings were
25 green, and they just lined up in green at TMI?

1 MR. REPLOGLE: Some of the findings at TMI were
2 green. Some of them weren't -- aren't -- still aren't
3 today modeled in PRAs. Most indications aren't modeled in
4 PRAs, so reactor vessel level -- reactor vessel level
5 indication in the heads, that's not generally modeled in
6 the PRAs.

7 So if the licensee has that inoperable for a
8 very long period of time, it's not going to change the
9 risk numbers. So that would be a green issue. But if we
10 look back at TMI and say, well, if the operators really
11 had good reactor vessel level head indication, they
12 probably wouldn't have secured safety injection and they
13 could have avoided core damage.

14 So if we find today that that indications has
15 been inoperable, non-functional for a whole year, chances
16 are that's going to be a green issue. But in the right
17 context, it could be, you know, significant.

18 All right. Strengths, I think this inspection
19 approach lets us look deeper into the design of the
20 individual components. Past engineering teams have been
21 conducted on a system-based approach, and there's only so
22 far you can look at when you're looking at a whole system.

23 A real system has maybe hundreds, thousands of
24 components when you look at all control circuits. This
25 approach we can take a pump, take a valve, and we just

1 inspect it all the way down to the bone.

2 This also helps us take a look at how the
3 licensee's been maintaining their design, where they've
4 had design lapses over time, because we're looking at the
5 initial design when the plant was licensed, what the
6 design is today, and we're comparing all the difference in
7 between.

8 The challenge, it's hard to be consistent.
9 We're human beings. It's very difficult to make every
10 human being on this inspection perform exactly the same
11 way. Some of our contractors are just world class; they
12 have the best minds in the industry. Some of them are at
13 the other extreme. The same thing with inspector skills.
14 Licensees --

15 DR. SHACK: Hope they're not that bad.

16 MR. REPLOGLE: Some licensees will figure out
17 pretty quickly it's not really in their best interest to
18 support us as much as we would like. And this inspection
19 is a pretty big drain on their resources. A lot of
20 licensees have trouble keeping up with the team.

21 And then team leader skills, some team leaders
22 can -- are better at evaluating conditions and coming up
23 and making a pretty good regulatory case. Others are less
24 skilled at doing that. And so we're trying to manage
25 those, but those are real-life inconsistencies, and they

1 affect the results.

2 All right. I'll give you an example of --

3 MR. MAYNARD: You might have to carry the
4 microphone with you.

5 MR. REPLOGLE: Give you an example of a couple
6 of findings that we've had at one plant. Here's a
7 refueling water storage tank at Calloway. And we selected
8 this system because it had 1 percent margin, design
9 margin, in this case.

10 And the first thing I'll talk about is this
11 instrument allowance for instrument uncertainty. Three
12 percent instrument uncertainty. That's what this amount
13 of volume is there to provide. And what -- we looked at
14 the licensee's corrective action program, and they had
15 identified, all on their own, that they hadn't accounted
16 for vortexing.

17 So they did a calculation and they said, well,
18 vortexing would take up about 2 percent of the volume, so
19 this 3 percent for instrument uncertainty, that covers
20 that, so we're okay. And I said, no, you need this for
21 instrument uncertainty; you need additional to account for
22 vortexing.

23 So in this case, what the licensee did is they
24 did sensitivity evaluation of the instruments that were
25 installed at the time, and they found that the instrument

1 drift was really less than 1 percent, so they were only
2 using about 1 percent of it. So in this case, the system
3 was still operable.

4 DR. CORRADINI: I think I know what you mean by
5 vortexing; you mean drawing in water when you're down at
6 the lower extreme when you have ECCS injection?

7 MR. REPLOGLE: Yes, just like when you flush
8 the toilet.

9 DR. CORRADINI: So let me ask, do all of these
10 have some sort of guards to stop vortexing, or these are
11 just open pipes?

12 MR. REPLOGLE: It depends. All the plants are
13 different.

14 DR. CORRADINI: So in this one.

15 MR. REPLOGLE: This one didn't.

16 DR. CORRADINI: Did?

17 MR. REPLOGLE: Did not.

18 DR. CORRADINI: Did not. And what does 2
19 percent -- I think you said 2 percent -- what does 2
20 percent translate into on a length scale?

21 MR. REPLOGLE: Oh, in a length scale?

22 DR. CORRADINI: Yes, pipe.

23 MR. REPLOGLE: I think the 2 percent accounted
24 for about two inches -- two to four inches, I think. It
25 wasn't a lot.

1 DR. CORRADINI: Okay.

2 MR. REPLOGLE: So our concern is --

3 DR. WALLIS: Why do they have that dead volume?
4 It just seems to be a waste to design a system with a dead
5 volume.

6 MR. REPLOGLE: It's just the way -- I think
7 it's just way it's designed, so the pipe doesn't suck in
8 stuff.

9 DR. WALLIS: Yes, but do you need 12 inches to
10 correct?

11 MR. REPLOGLE: Yes, this is where the top of
12 the pipe is --

13 DR. WALLIS: I know, but it seems a bit odd to
14 put it there.

15 MR. REPLOGLE: Yes.

16 DR. WALLIS: I mean, the drain from my bathtub
17 isn't 12 inches off the bottom of the bathtub.

18 MR. REPLOGLE: That's true.

19 DR. CORRADINI: What surprises me more is the
20 fact that they said two inches is all you need to
21 accommodate vortexing.

22 MR. REPLOGLE: Okay. I'll do it. All right.
23 Now, here's a second issue. When you have your large-
24 break loss-of-coolant accident, six pumps take the suction
25 off this tank and suck down all at the same time so the

1 level starts coming down.

2 This vent at the top has to be designed to
3 account for that level decrease, and it has to let in an
4 equal amount of air as there is water going out.

5 Our contractor looked at the calculation for
6 the vent and then the vent sizing calculation, which had
7 been there since the plant was built, had only assumed
8 that one pump started. So that was a mistake. They
9 should have assumed that six pumps started.

10 DR. WALLIS: Does the tank collapse in that
11 case?

12 MR. REPLOGLE: Well, it had a structural
13 integrity value of only a few inches of water. So
14 originally they had sized the vent -- this is a very big
15 tank, and that vent's really much smaller than I've draw
16 it there. Here's the actual vent. They thought they had
17 60 percent margin, and when pointed out this error, they
18 said, well, we're okay because we have 5 percent margin
19 left.

20 And what we said was, you know, a bird nest
21 could cover that 5 percent. You know, how do we know
22 there's not a bird nest or something up there? The
23 opening's four inches; the diameter of this pipe is 16
24 inches.

25 And so they went up there and looked, and what

1 they found was this fine mesh screen covering a vent that
2 they had put up there for some other work and they had
3 forgotten about it and left it up there in 2002.

4 Now, ice storms, they have ice storms at
5 Calloway; that can cover over 5 percent. So they took
6 that off, and as we were leaving the site, they had an ice
7 storm, and so that's just-in-time inspection on our part.

8 But this issue, we couldn't determine that the
9 system was operable with this vent on there with this
10 extra mesh screen on there. So this is an instance where
11 for a large-break loss-of-coolant accidents, when they had
12 an ice storm, at least when they had an ice storm, this
13 system may not have been able to perform its safety
14 function, but it was green because of the risk.

15 DR. WALLIS: I would think snow would work too.
16 I mean, if you use it in a snow storm, the snow would pack
17 up on the screen, wouldn't it?

18 MR. REPLOGLE: That's true. That's true. So
19 there is a number of things that could clog this up. And
20 that's all I had, unless there are any additional
21 questions.

22 DR. WALLIS: So what did you do about it, take
23 off the screen?

24 MR. REPLOGLE: They took off the screen.

25 DR. MALLETT: I'd like to add I think George

1 undersells himself and the rest of the rest of the people.
2 These component design inspections have gotten us a lot
3 more deeper into the design and found things at facilities
4 that we didn't realize and they didn't realize were a
5 problem, and they fixed them.

6 In almost every place they've gone they found
7 significant design issues.

8 DR. WALLIS: Well, I bet that's not in the PRA.

9 DR. MALLETT: I don't know the answer to that,
10 George.

11 DR. WALLIS: That screen isn't in --

12 DR. MALLETT: It probably wasn't --

13 DR. WALLIS: -- the PRA.

14 DR. MALLETT: -- in the PRA.

15 MR. REPLOGLE: Failure of the tank would be in
16 the PRA, but this wouldn't be.

17 MR. MAYNARD: This type of inspection, it's
18 very demanding on the NRC and on the licensee. But it is
19 going back to things that probably haven't been looked at
20 in many cases since the original design back in the '70s-
21 '80s time frame when a lot of these designs were done. So
22 there is a lot of fruit to come out of these inspections.

23 DR. SHACK: Was this something that found the
24 software air problem at Palo Verde in that core
25 calculator, or did that come out of some other inspection?

1 MR. WARNICK: We don't know the answer to that
2 question. We can get back to you.

3 DR. MALLETT: I'm just wondering how some of
4 these latent errors are found. I mean, they just --

5 MR. WARNICK: That was something identified by
6 the --

7 MR. MAYNARD: They need to use a microphone.

8 MR. WARNICK: I'm sorry. This is Greg Warnick,
9 senior resident. That -- they've upgraded their core
10 protection calculators in units 1 and 2, and that was a
11 flaw identified by the vendor.

12 MR. MAYNARD: What I'd like to do now, if we
13 could, we'll take a break. We'll come back and we'll have
14 a roundtable discussion here, and I think any of these
15 issues that we've been talking about, to give us an
16 opportunity to revisit any of those and to spend some more
17 time on that.

18 So what I'd like to do is we'll take a break
19 until 2:40, and we'll be back in here and then start a
20 roundtable discussion.

21 (Whereupon, a short recess was taken.)

22 MR. MAYNARD: We'll get started. We have a
23 couple of members out, but this is a fairly informal part
24 of the session; it's just dialogue back and forth, and
25 we'll discuss things.

1 We're back on the record. I'll turn it back
2 over to Tony to introduce some of the folks.

3 MR. GODY: Thank you, sir.

4 What I'd like to do is introduce the members of
5 the panel here, and I guess I'll go myself first. My name
6 is Anthony Gody; I'm chief of the Operations Branch. I've
7 been the chief of the Region IV Operations Branch since
8 2004 -- I'm sorry, 2001, and I started in Region IV in
9 1994 as the senior resident inspector at Comanche Peak.

10 I did join the NRC in 1989 as a project manager
11 in the Office of Nuclear Reactor Regulations, and prior to
12 the NRC I was a naval officer. Went to the University of
13 Florida, one of the best engineering schools in the
14 country, and --

15 MR. MAYNARD: Oh, that'll start some debate.

16 (General laughter and discussion.)

17 MR. GODY: And I also was an enlisted man in
18 the Navy also as a reactor operator.

19 As I introduce individuals, either raise your
20 hand or stand up. Kelly Clayton is currently a senior
21 operations engineer in Region IV. Kelly is originally
22 from Texas and a graduate of the University of Texas at
23 Austin with a bachelor of science degree in chemical
24 engineering.

25 DR. APOSTOLAKIS: How good is that school?

1 MR. GODY: That's pretty good.

2 DR. APOSTOLAKIS: Okay. Good.

3 MR. GODY: With a specialty in digital
4 controls. Prior to joining the NRC, Kelly spent six years
5 in the United States Navy as a load dispatcher and nuclear
6 plant operator/supervisor. Mr. Clayton, or Kelly we call
7 him, worked for Fisher-Rosemount [phonetic] Systems as a
8 senior controls engineer installing and testing digital
9 controls equipment in over 168 locations for companies
10 such as Exxon, Georgia-Pacific, Merck and Bayer.

11 Kelly joined the NRC in 2002 and currently
12 works for the Operations Branch.

13 MALE VOICE: Hopefully he was not dispatching
14 nuclear loads.

15 MR. GODY: Okay. Paul Elkmann. Paul has a
16 bachelor of science degree in physics from Case Western
17 Reserve University in Cleveland, Ohio, and a master of
18 science degree in radiation biology, University of Iowa.

19 He currently is an emergency preparedness
20 inspector and he is also a reactor health physics
21 inspector and he works in the Division of Reactor Safety,
22 Operations Branch. And he's been with Region IV for eight
23 and a half years. As a collateral assignment, Paul also
24 is the Region IV dosimetrist.

25 Prior to joining NRC, Paul was an emergency

1 planning specialist for Carmen Wolf Edison [phonetic]
2 Company, health physicist for the State of Iowa public
3 health and health physics technician for Canberra.

4 Greg Warnick. Greg Warnick first joined the
5 NRC in 1997 as a project engineer in NRC Region II's
6 office in Atlanta. In 1998 Greg was assigned as a
7 resident inspector at the St. Lucie Nuclear Power Plant in
8 St. Lucie, Florida.

9 In December of 2000, Greg transferred to Region
10 IV, was assigned as a resident inspector of the Palo Verde
11 Nuclear Generating Station. In 2004, Greg was promoted to
12 the position of senior resident inspector at Palo Verde.

13 Prior to joining the NRC, Greg was employed as
14 a nuclear plant engineer with Lockheed-Martin, Knolls
15 Atomic Power Laboratory.

16 Greg graduated from Brigham Young University
17 with a bachelor of science degree in mechanical
18 engineering in 1993.

19 George Replogle.

20 MR. REPLOGLE: You can skip mine.

21 MR. GODY: Okay -- no. Mr. Replogle is
22 currently senior project engineer in the Division of
23 Reactor Projects. Previously Mr. Replogle worked as a
24 senior engineer in the Division of Reactor Safety, and
25 held senior resident inspector positions at Columbia

1 Generating Station and River Bend.

2 George also worked as a resident inspector at
3 Columbia Generating Station, and served as a reactor
4 inspector in Region III Division of Reactor Safety.

5 Overall George has over 20 years of government
6 service. He has a bachelor of science degree in
7 mechanical engineering from Sacramento State University,
8 an associates degree in electronics technology from Orange
9 Coast College. Mr. Replogle has also completed graduate
10 level work towards a master's degree in business
11 administration.

12 MR. MAYNARD: Did he work at Columbia
13 Generating Station as an employee, and then also was there
14 as a resident inspector, or did I get --

15 MR. REPLOGLE: No, I was a resident inspector,
16 and then I went to River Bend to be a senior, and then I
17 came back as a senior resident inspector.

18 MR. MAYNARD: So you -- okay.

19 MR. GODY: So he held both the resident and
20 senior positions.

21 MR. MAYNARD: Okay.

22 MR. GODY: Dave Loveless. Dave Loveless
23 currently is a senior reactor analyst in the Division of
24 Reactor Safety, and he's been in that position for about
25 six years. Major positions in the past: He was senior

1 resident inspector at South Texas project, resident
2 inspector at River Bend and Sequoyah.

3 He also worked at the Accident and Evaluation
4 Branch in the Office of Nuclear Reactor Regulations, and
5 he worked for the licensee as a nuclear engineer at
6 Calvert Cliffs Nuclear Power Plant.

7 He has a bachelor of science degree in nuclear
8 engineering from Rensselaer Polytechnic Institute. That's
9 why they're small letters. He completed the senior
10 reactor analyst certification program, the resident
11 inspector certification program, and he currently has --
12 also has a nuclear technology certificate from Chattanooga
13 State College.

14 Jim Drake. Jim is currently an operations
15 engineer in Operations Branch. He served in the United
16 States Navy prior to the NRC as a junior officer, combat
17 systems officer, engineer, and squadron engineer in the
18 Mediterranean and as an intelligence office with NATO.

19 He qualified chief examiner, emergency planning
20 inspector, and reactor inspector while he's been at he
21 NRC.

22 He also enlisted in the United States Navy in
23 1977 as an interior communication technician. He attended
24 the D-1 G and the MARV prototypes. And he has a bachelor
25 of science degree in electrical engineering from the Naval

1 Academy, and a master of science degree in systems
2 technology from the Naval Post-Graduate School.

3 Paul Bonnett. Paul Bonnett received his
4 initial training from Naval Nuclear Power School in 1973.
5 He graduated from Thomas Edison State College in 1990 with
6 a bachelor of science degree in nuclear engineering
7 technology.

8 In 1983 he went to work for Public Service
9 Electric and Gas Company and licensed as a nuclear control
10 operator at Hope Creek Generating Station, which was
11 currently under construction at the time.

12 In June of 1986 Paul formed the Initial
13 Criticality Historical Unit. He joined NRC at Region I in
14 September of 1988 as a licensed examiner. He certified as
15 an inspector and became a senior operations engineer.

16 He assisted in the Operator License Branch at
17 headquarters in developing guidance for senior reactor
18 operator limited to fuel handling series in the
19 examination standard -- and we need to talk about that.

20 He was the chief examiner on the pilot exam at
21 Limerick Generating Station, and between 1992 and 2000,
22 Paul was a resident inspector at Peach Bottom Station, and
23 then Limerick Station. And he was assigned to the Region
24 I Tech Support Organization in 2000.

25 In August of 2003 Paul became the program

1 analyst in the Office of Regional Administrator providing
2 inputs for the annual regional operating, metrics and
3 budget.

4 In January of 2004 Paul joined the Inspection
5 Program Branch, now the Reactor Inspection Branch in the
6 Office of Nuclear Regulation, and managed the ROP feedback
7 process and several inspection procedures.

8 He was recently promoted to senior reactor
9 analyst and completed a certification. He is currently
10 the program lead for the Significance Determination
11 Process.

12 John Hanna. John Hanna's currently the senior
13 resident inspector at Ft. Calhoun. He joined the NRC
14 Region IV in 1997 as a reactor inspector in Branch Bravo
15 of the Division of Reactor Projects. He has also been the
16 resident inspector at ANO, Calloway, acting senior
17 resident at River Bend and Turkey Point.

18 John attended Georgia Tech specializing in bio-
19 engineering and graduated in 1990. Immediately following
20 college he started working for the Navy as a ship test
21 engineer, and he did some work on fast attack submarines
22 and a great deal of work on cruiser refuelings and
23 decommissionings, and was cross-qualifying to carriers
24 when he came to work for the NRC.

25 John lives in Omaha, Nebraska with his wife

1 Heather.

2 MR. MAYNARD: That's a good thing, because
3 that's where Ft. Calhoun is. It'd be a long drive every
4 day if he lived here.

5 MR. HANNA: It makes it a little bit easier to
6 get to work, yes.

7 MR. MAYNARD: Okay. If that's the
8 introductions, what I'd like to do is, again, kind of open
9 up for anything that we've discussed today, and really
10 anything else is fair game too we could talk about.

11 I'd like to start off with George and see -- I
12 kind of cut you off a while ago -- and to see if you've
13 got your questions answered, or if you want to pursue that
14 anymore.

15 DR. APOSTOLAKIS: I think we have a response to
16 the issue of operators sleeping.

17 MR. WARNICK: Yes, actually Tony was going to
18 get an answer to that --

19 DR. APOSTOLAKIS: Okay.

20 MR. WARNICK: -- on how it's going to be
21 handled through the ROP.

22 MR. GODY: Okay. I didn't think I was going to
23 start right off the bat. Okay. The question earlier was
24 surrounding whether or not we would deal with an operator
25 issue in the SDP, and the question is -- has to do with

1 how would we deal with an operator -- human performance
2 type issue in the SDP.

3 Well, there's -- we can do this through a
4 number of different examples, but at one facility -- and
5 I'm going to avoid plant names, even though it's public
6 material -- at one facility an operator was removing a
7 strip chart recorder and in the process of doing that
8 dropped it, and it resulted in a plant transient.

9 We evaluated the fact that he had that --
10 what -- did not provide -- or do adequate self-checking
11 and peer checking, and adequate attention to detail when
12 he was removing that strip chart recorder, and we
13 identified that there was a transient associated with
14 that, and the performance deficiency resulted in some type
15 of plant impact.

16 So what we did was we assessed the plant impact
17 and assigned the risk of that issue, the risk
18 determination from that issue, based on the plant impact.

19 Is there anybody else in here that knows this
20 detail, this issue, better than that?

21 MR. LOVELESS: I was the team -- I'm David
22 Loveless. I was the team leader for the special
23 inspection, and Jim here was also on that team.

24 From a -- how it worked in the program, we
25 identified a number of performance deficiencies during

1 that inspection. The one in particular with how the
2 operator handled the chart recorder was also tied back to
3 some other issues that the -- where the licensee had had
4 problems working over panels, but --

5 MR. MAYNARD: To clarify, I'm assuming that by
6 dropping -- he dropped it on something on the control
7 panel that caused the --

8 MR. LOVELESS: Yes, it dropped on the control
9 panel. It actuated isolation of the feed water system and
10 caused a reactor scram as a result.

11 The -- but once we identified the performance
12 deficiencies associated with that event, and some of the
13 surrounding issues, we take those, each of those issues,
14 we look at -- then we put them into the significance
15 determination process.

16 We then process each individual performance
17 deficiency in an isolated case within its cornerstone.
18 And in this case all of the findings that we had were
19 green, and based on specific risk associated with any
20 given performance deficiency.

21 Now, the total risk associated with the even
22 was higher, but our significance determination process
23 looks at just those individual actions where the licensee
24 made an error, or where they had a performance deficiency.

25 MR. WARNICK: Can you remember what -- how much

1 the risk was from this event?

2 MR. LOVELESS: We only did a preliminary on
3 that, but it was in between a 10^{-6} and 10^{-5} per reactor
4 year, core damage frequency associated with the event.

5 DR. APOSTOLAKIS: But I guess I don't quite
6 understand this. There was a transient. Right? What is
7 the performance deficiency in this case? I mean, what is
8 it that goes into the SDP?

9 MR. LOVELESS: Okay. Well, one of the rules
10 that came up very early on, and has followed through in
11 the ROP is that we do -- will not evaluate an event under
12 the SDP. So the fact that there was an event, we don't
13 look at the conditional core damage probability of that
14 event and apply it to the licensing performance
15 deficiency.

16 So what we have to look at is this operator
17 made an error, we saw other operator errors that were
18 similar to this, we had a control panel that was
19 unprotected. So we looked at over a time frame what's the
20 probability that this would occur, even though we know it
21 occurred that one time, what's the frequency with which
22 that kind of error occurs. And then we looked at the risk
23 of the --

24 DR. APOSTOLAKIS: Are you looking at the
25 individual? In other words you are looking at the

1 significance of the panel being unprotected and then you
2 look at the significance of the error. Or do you consider
3 the error plus the fact that it's unprotected?

4 MR. LOVELESS: We only look at single human --
5 or single licensee performance deficiencies. And so if a
6 licensee performance deficiency is seen as -- a single
7 performance deficiency is seen in a number of problems,
8 then all of those problems would be assessed for
9 significance together to look at the risk of that
10 performance deficiency.

11 But if you have a single performance deficiency
12 isolated from any other, then we would look at the risk
13 just of that --

14 DR. APOSTOLAKIS: Not about this --

15 MR. LOVELESS: -- particular --

16 DR. APOSTOLAKIS: -- time. Do you look at all
17 the things he might have dropped it on, or something like
18 that? I mean, there's a whole spectrum of things if you
19 start looking at dropping things on the control panel.

20 MR. LOVELESS: Well, I understand, and I was
21 trying to avoid getting into the actual risk analysis
22 aspects of it in this particular case.

23 MS. BANERJEE: No, David, give him an example
24 of one of the performance deficiencies. He dropped it, he
25 didn't look right away and see what --

1 MR. LOVELESS: Yes, that was -- one of the
2 performance deficiencies was that he dropped it, scooped
3 it up, took a quick look around and took it over to fix
4 it. And a second performance deficiency that was related
5 to that was the two senior operators walked by that panel
6 between the time he dropped it --

7 DR. APOSTOLAKIS: Meanwhile there's no feed
8 water --

9 MR. LOVELESS: -- and the time that the reactor
10 scrammed, feed water is isolating and none of these
11 operators recognized that feed water was isolated. So
12 those -- that -- those are two different performance
13 deficiencies that we would evaluate.

14 Now, both of those performance deficiencies
15 would be very low in risk because the time frames
16 associated with it, it was only a couple of minute window,
17 and so that risk would be very low. Now, the --

18 DR. APOSTOLAKIS: Couldn't you restore feed
19 water before the reactor scrammed?

20 MR. LOVELESS: We looked at it. We believe
21 that they could have restored in this particular case.

22 DR. APOSTOLAKIS: And, again, you say you look
23 at them in isolation, so they'd been noticed, because it
24 was the feed water system had stopped. Correct?

25 MR. LOVELESS: Correct.

1 DR. APOSTOLAKIS: Are you now evaluating -- are
2 you --

3 VOICE: Oh, I'm sorry.

4 DR. APOSTOLAKIS: -- are you evaluating --

5 MR. LOVELESS: No, no, I misunderstood what you
6 said. You said that the --

7 DR. APOSTOLAKIS: What did -- the senior
8 operators walked by, what is it that they did not notice?

9 MR. LOVELESS: The only thing on the panel at
10 the specific time would have been that two push buttons
11 that were in the full open position were now popped to
12 where they would have been at a neutral position,
13 indicating that the valves weren't in their proper
14 position.

15 DR. APOSTOLAKIS: Okay. But there were some
16 enunciators. Right?

17 MR. LOVELESS: They had not gotten enunciators
18 at that point, and there were some indication problems, so
19 it got much more complicated than that, but there were
20 indications that were difficult to detect, but given that
21 somebody had just dropped a heavy piece of equipment on
22 top of the control panel --

23 DR. APOSTOLAKIS: And they knew that --

24 MR. LOVELESS: -- we would have expected that
25 operators would have looked at things.

1 DR. APOSTOLAKIS: And they knew that, they knew
2 that somebody had dropped --

3 MR. LOVELESS: Oh, everybody in the control
4 room knew --

5 DR. APOSTOLAKIS: But when you do --

6 MR. LOVELESS: -- that it dropped.

7 DR. APOSTOLAKIS: -- when you do the SDP, are
8 you evaluating or determining the significance of this
9 specific incident or deficiency, or are you assuming that
10 they never noticed about those being out of place and so
11 on?

12 MR. LOVELESS: Well --

13 DR. APOSTOLAKIS: The reason why I'm asking is
14 because in PRA, the more you go down to the causes and the
15 details, the less significant these events become. So do
16 we have an inherent problem here where we're looking at
17 something so detailed that we know in advance the CDF
18 change will be insignificant?

19 MR. LOVELESS: Under our program, we do have a
20 number of personnel actions that, because of their nature,
21 will not show up as significant performance deficiencies.
22 We look at those in a number of different ways.

23 If we have common thread performance
24 deficiencies where we know that the training was wrong and
25 that they're not doing a set item -- they're not doing

1 something they're supposed to and they're always not doing
2 what they're supposed to, then we can look at that using
3 our probabilistic tools and determine what the risk of
4 that broader performance deficiency is.

5 But, yes, our -- as an analyst, my job is to
6 look at the performance deficiency as scoped by the
7 inspectors in the field.

8 DR. ABDEL-KAHLIK: So when you say that the
9 estimated core damage frequency associated with that 10^{-5}
10 to 10^{-6} , you were talking about evaluating this
11 inadvertent feed water isolation event by itself, or are
12 you evaluating other events that could have potentially
13 happened from dropping something on an unprotected panel
14 in general?

15 MR. LOVELESS: That was the conditional core
16 damage probability of the event that occurred. We -- not
17 in the SDP, in our what we call management directive 8.3,
18 when we decide whether we want to have a reactive
19 inspection for something that's occurred, we look at,
20 given the initiator that occurred, but assuming that a
21 random probability of components and equipment failing
22 beyond that initiating time, what's the probability that
23 it would go to core damage very similar to what an ASP
24 would look at.

25 DR. ABDEL-KAHLIK: The initiating event is

1 someone dropped something. Right? I mean, this thing
2 could have dropped on the edge of the panel, touched
3 nothing, and would have had no impact. But still, it is a
4 significant event in and of itself, so how would you
5 assign a core damage probability or a significance to an
6 event of that type?

7 MR. LOVELESS: Okay. In that particular
8 circumstance, what we evaluated was -- we evaluate at what
9 we call an initiator, which is a transient reactor scram,
10 a loss of offsite power, a loss of --

11 VOICE: A loss of normal --

12 MR. LOVELESS: -- coolant, those sort of
13 things. So the time zero that we would have started with
14 as our initiator would have been the reactor scram on loss
15 of feed water. It wouldn't -- we wouldn't have analyzed
16 given somebody dropped something on the panel, what's the
17 probability that that goes on.

18 Now, we do some of that type of analysis when
19 we're looking at the SDP for the performance deficiency.
20 But when we're assessing the risk of an event, we start
21 with the actual demand for the rods to go in the reactor.

22 DR. APOSTOLAKIS: But I thought you said
23 earlier that you will not do an ASP kind of analysis.

24 MR. LOVELESS: That assessment is not an SDP --

25 DR. APOSTOLAKIS: ASP. And I was -- you said

1 that before, you said that --

2 MR. LOVELESS: Yes.

3 DR. APOSTOLAKIS: -- the fact that you had a
4 transient is not something you analyze. You're looking
5 for deficiencies and you're analyzing deficiencies.

6 MR. LOVELESS: We don't analyze it under the
7 significance determination process in order to look at
8 where we fall in the action matrix. As an analyst, I do
9 analyze pretty much every reactor scram and many
10 significant degraded conditions, and I look at the total
11 risk of that.

12 And that total risk helps us determine whether
13 we're going to do reactive inspections, special
14 inspections, augmented inspections.

15 DR. APOSTOLAKIS: But that doesn't go into the
16 action matrix?

17 MR. LOVELESS: The risk of the --

18 DR. APOSTOLAKIS: Oh.

19 MR. LOVELESS: -- event that we look at
20 initially does not go in the action matrix, because that
21 may or may not have been related to a performance
22 deficiency.

23 DR. APOSTOLAKIS: So that several issues, you
24 have an event, you analyze it outside the action matrix,
25 and you get a condition for damage probability, you

1 declare whether you want to have additional inspections.
2 Now, that event, you look at it more carefully, and you
3 say, well, there were three causes that contributed to it,
4 like he dropped it, and so on.

5 Then you have make a determination whether each
6 of these contributing events, sub-events, is a deficiency
7 or not, because things do happen at random too, I mean.
8 So that's a first judgment. Then you decide that each one
9 was indeed a deficiency, that each one would be put in an
10 SDP calculation independently of the other two.

11 MR. LOVELESS: That's correct.

12 DR. APOSTOLAKIS: And then my suspicion is that
13 by doing that, you are bound to get very low
14 probabilities.

15 MR. LOVELESS: And at times that's true.

16 DR. APOSTOLAKIS: Well, even today. Because
17 these are very little things. I mean it's -- when you
18 have the compound event, that's bigger problem.

19 MR. LOVELESS: Let me give you one good
20 example. It would be a loss of offsite power. If a
21 transmission grid, may not even be the same operator that
22 owns the reactor, has a loss of major lines coming into
23 the plant, and that loss of power to the plant causes them
24 to lose all offsite power, they trip, they go on their
25 emergency offsite power.

1 That's a very significant event, but that may
2 not -- in that event, there may not be any performance
3 deficiency related to licensee performance. So -- but
4 there's a very high risk peak. And in the SDP itself and
5 the action matrix, we're trying to assess how well is the
6 licensee performing, and the licensee's performance wasn't
7 degraded; it wasn't indicative that they were degraded.

8 In fact, if there are no performance
9 deficiencies from that loss of offsite power, it may be
10 indicative that they're doing very well, that they're able
11 to handle that type of transient.

12 So we get the -- we have two different metrics.
13 One is the risk associated with the event that occurred,
14 and that tells us do we need to spend our time to look at
15 it, and the other is what's the risk of the performance
16 deficiencies when the licensees make mistakes.

17 DR. APOSTOLAKIS: That brings to mind what
18 happened in Sweden; I think it was Ostershom [phonetic] or
19 one of those, where there was a loss of offsite power, and
20 as I recall they had four diesels, and two failed to stop.
21 Now, following the logic you just described, the loss of
22 offsite power and the whole responsibility of the facility
23 that's something you will look into, but it's not part of
24 the SDP.

25 However, the fact that two diesels did not stop

1 our of the four makes you suspicious and you look into
2 that occurrence trying to see whether there is a
3 performance deficiency that led to that --

4 MR. LOVELESS: Absolutely.

5 DR. APOSTOLAKIS: -- and if you find a
6 performance deficiency that is common to both diesels,
7 then you process that deficiency through the SDP. Is that
8 correct?

9 MR. LOVELESS: Absolutely.

10 DR. APOSTOLAKIS: And you will assume in the
11 way that that deficiency perhaps could have failed all
12 four with some probability. Is that correct?

13 VOICE: Yes.

14 MR. LOVELESS: Yes.

15 VOICE: He's absolutely correct.

16 MR. LOVELESS: We've actually had that
17 before --

18 DR. APOSTOLAKIS: Yes, and then you --

19 MR. LOVELESS: -- in Palo Verde.

20 MR. GODY: Yes, I was going to say the Palo
21 Verde loss of offsite power event, the event itself was
22 significant. They lost a considerable amount of
23 generation. There was a momentary blackout in Phoenix, a
24 significant emotional event for that area.

25 But when we did -- I was actually the leader of

1 that augmented inspection team, and we determined that it
2 met the criteria for having a team immediately go out and
3 assess the event. When we were done we had over 15
4 findings from that event, 15 or so performance
5 deficiencies of the facility. One of them involved
6 decreasing the reliability of some of the offsite lines.

7 So what we do is we'll go out and we'll send a
8 team of inspectors out based on the risk, or the
9 significance of the event that's determined by the senior
10 reactor analyst, and we'll assess performance. And each
11 one of those performance deficiencies that's identified
12 will be assessed as a standalone issue.

13 DR. ABDEL-KAHLIK: Let me just ask about the
14 other end, the other extreme of this scenario. Let's say
15 the operator dropped this chart recorder on the edge of a
16 panel, nothing happened. Would you have heard about it?

17 MR. LOVELESS: It's quite possible we would
18 have heard about it, because we have the resident
19 inspectors on site. It's also possible that we wouldn't
20 have heard about it. In our better performing plants we
21 would see trending where they would be looking at operator
22 errors at that level. Some of our plants we might not
23 see --

24 DR. BONACA: Would the licensee report the
25 condition if nothing -- if there was no consequence?

1 MR. BONNETT: It's possible that if he dropped
2 the chart recorder and nothing occurred, and the licensee
3 was -- had a low threshold for putting things in their
4 corrective action system, that would have been entered
5 into that.

6 Had we heard about it in a morning meeting or
7 something like that, gone and looked into it, we would
8 have found that they've already identified it, put it in
9 their corrective action system, and then we wouldn't we
10 follow up on it after that since they've already taken
11 actions towards that. It would be more or less licensee
12 identified.

13 Had they not done that, and we brought that
14 back and we brought it to the SRAs to do an assessment
15 about that, it could turn out to be a finding because
16 the -- it was a performance that wasn't captured or looked
17 at by the licensee.

18 DR. BONACA: It could still be a defective
19 control room design, for example, okay, that leads the
20 operator to drop --

21 VOICE: Right.

22 DR. BONACA: -- this --

23 MR. BONNETT: Well, I think that's a -- most
24 control room designs are going --

25 DR. BONACA: Well, that's what I'm saying.

1 That's why it --

2 MR. BONNETT: Right.

3 DR. BONACA: -- would go in the corrective
4 action system, because you want to evaluate to make sure
5 that if there is, in fact, a design deficiency --

6 MR. BONNETT: Sure.

7 DR. BONACA: -- that you have a frequent
8 operation, for example, that may lead you to drop this on
9 the console.

10 MR. BONNETT: And that would give us an
11 indication of the health of their corrective action
12 process.

13 MR. GODY: Exactly. There may be some kind of
14 detent on the device that would prevent it from falling
15 out of its rack, and that detent could have been degraded
16 or broken, and -- which it was in this case, and we would
17 expect them to put it in their corrective action program
18 because it is a condition adverse to quality, and that's
19 required by 10 C.F.R. Part 50, Appendix B, Criterion 16.

20 DR. ABDEL-KAHLIK: But that's where my concern
21 about the mechanics of the process comes from. In a sense
22 that -- regardless of what the consequence of the initial
23 event, which is dropping of something on the console is,
24 whether the isolated feed water or initiated high pressure
25 safety injection, whatever the outcome, these are all

1 caused, or potentially were caused by the same thing.

2 And when you say the analysis starts by looking
3 at the event itself rather than what caused the event,
4 then I'm not sure what's the value of this process.

5 MR. LOVELESS: Remember we were talking about
6 two different processes. One is our process to determine
7 if there's a -- if we need to have a reactive inspection,
8 send out additional resources beyond the resident
9 inspectors to take a look at the event. That's the
10 analysis that I was talking about that starts with the
11 event and says, okay, the event occurred, what's the risk
12 of having that event tomorrow, the same event.

13 When we did analyze this specific evaluation,
14 we went all the way back -- we went back well before the
15 actual event. We looked at other events where they
16 dropped things on the panels and how they handled it. And
17 we looked at operator training in these areas, and we
18 looked at failures of the same mechanism that failed in
19 the recorders.

20 VOICE: Operator experience at other plants.

21 MR. LOVELESS: Yes, we pulled in operator
22 experience from other plants, that sort of thing.

23 MR. WARNICK: I'd just like to say something.
24 This is Greg Warnick, senior resident at Palo Verde.

25 It really gets to the threshold that the

1 licensee has in the corrective action program as it was
2 stated earlier. An interesting example that I'd like to
3 share of Palo Verde, just weeks after this event happened
4 at this facility -- you know, the rest of the industry
5 were aware of it, there are daily reports that go out
6 about a reactor plant tripping off.

7 Well, it was us inspectors that were walking
8 through the control room and noticed that they had the --
9 had several of their instruments pulled out from the
10 panel, and they were just sitting in the withdrawn
11 position.

12 We walked in there and asked why are those
13 instruments withdrawn, is that okay? Well, they stated to
14 us, well, that's what we always do. If the paper's
15 running out we pull it out so we can see when the paper's
16 out, we leave it there for a few hours, and at that point,
17 when we see it's pulled out, we'll change the paper.

18 Well, we asked if that was all right in light
19 of what just happened at this other facility with an
20 instrument falling on the panel and causing a reactor
21 trip. Well, they said they didn't know if that was wrong,
22 but that's how they'd always done it.

23 Well, as they looked into it, it turns out in
24 this withdrawn position they were not seismically
25 qualified. So it was a poor -- that's an example of a

1 facility that didn't have a good threshold, they knew
2 about this other example that happened of something
3 falling.

4 But they failed to ask themselves what could
5 that mean to us? Is this practice that we use, could that
6 cause a problem with us? You asked if we, the residents,
7 would find out about it if they dropped something and it
8 didn't affect anything.

9 Well, it depends on the threshold that the
10 licensee has. If the individuals who dropped it and
11 nothing happened stop and question themselves, hey, what
12 if that fell on this button, or what if this fell
13 somewhere else, what could have happened? If they have a
14 good questioning attitude, a good threshold, they'd put
15 that in their corrective action program to do something
16 about it.

17 What we saw at Palo Verde is they didn't
18 question themselves on that. They didn't have a good
19 threshold. It took the inspectors, on our daily
20 observations, to go in and say, hey, in light of what
21 happened, you know, that just doesn't look right. Why is
22 that okay?

23 VOICE: And, Greg --

24 DR. APOSTOLAKIS: Wouldn't that depend on an
25 SDP? You would find a very low probability -- right? --

1 because the earthquake must occur first, which is
2 fairly --

3 MR. WARNICK: That's correct, but --

4 DR. APOSTOLAKIS: -- everything has to
5 follow this --

6 MR. WARNICK: That's right. But it's important
7 for us to go out and identify these things so that it
8 doesn't lead to a more significant issue.

9 DR. APOSTOLAKIS: Not about this. Just the SDP
10 that's --

11 MR. GODY: And Greg's got a good point here.
12 If you actually were to look at some of the findings that
13 we have in our region, there's numerous examples where the
14 inspectors have identified findings at one utility and
15 then go out to another utility and find the same findings.

16 For example, in the emergency preparedness area
17 we found that at one facility the licensee was not
18 adequately tracking equipment that they rely on in their
19 emergency plan when it was out of service, and -- but this
20 particular facility was seismic monitors, and it was in
21 California.

22 And they had EILs that were driven directly off
23 of that seismic monitor and had been out of service a lot.
24 So we actually raised that as an industry issue, and I
25 don't know, Paul, if you wanted to talk a little bit about

1 that or not, but we found issues in other facilities
2 that --

3 DR. APOSTOLAKIS: So the natural conclusion
4 from that then, the first conclusion, is that they should
5 improve the way of learning from the experience of other
6 facilities. Right?

7 DR. BONACA: One thing I wanted to say,
8 assuming that dropping this component on the console --
9 I'll give you three scenarios, one is that nothing happens
10 because he's on one side and so a guy gets lucky. At the
11 most they may have some entry to the corrective action
12 program.

13 Second scenario, we have a scram, as they did;
14 nothing much happens, but, you know, they get the green
15 maybe. In the third one, they have a transient that leads
16 very close to core damage. It doesn't go to core damage,
17 but it's -- in that case this operator may get, you know,
18 a white or a red. Okay.

19 So I'm saying at times I really wonder too, I
20 mean, depending on how lucky he is, you know, he ends up
21 with a very different outcome from the regulatory
22 oversight process.

23 MR. WARNICK: Well, carrying that on a little
24 bit more, with the Palo Verde issue that we found where
25 they didn't learn from the mistakes of others, they didn't

1 recognize at a good threshold what the significance of
2 their practice was. We did issue a finding; sure, it was
3 a green significance; there was no seismic event involved.

4 However, we did see that there was a PIR cross-
5 cutting aspect about that. They failed to learn from
6 other facilities, they failed to have a good threshold,
7 and those cross-cutting aspects roll up into our
8 assessment.

9 At Palo Verde we say that they have a
10 substantive cross-cutting issue in PIR. That means that,
11 we believe, through our assessment process, that they
12 don't have a good threshold.

13 So because of that, they have to take actions
14 to correct that threshold so that in the future, as we
15 continue to inspect through and they correct their
16 problems, they'll get to the point where it's not us
17 saying, hey, why is that instrument withdrawn, but they'll
18 use the OE program, say, hey, look, this happened
19 somewhere else, what does that mean to us, and they can
20 fix those problems themselves.

21 MR. GODY: Right. And then, Dr. Bonaca, the --
22 what it would mean is that the licensee that had the
23 instrument bounce off the control panel and there was no
24 event may not get any additional inspection. The licensee
25 that had this device hit the panel and they had a

1 significant plant event may get an augmented inspection
2 team which might have eight or ten people on it.

3 So assessing the significance of the event
4 determines our response to the licensee.

5 DR. BONACA: Yes, I just -- the reason there's
6 an issue in the sense that -- assumed that this was, in
7 fact, caused by deficiency in design of this panel, that
8 you had a routine performance, something that the operator
9 has to repeatedly do every few days or weeks, and every
10 time it brings you close to an event, because it's hard to
11 reach or something. Okay.

12 So therefore you -- the same deficiency,
13 however, my come in a very different regulatory outcome
14 depending on how lucky the guy is, I mean, whether it hits
15 the panel. And it seems to me that the -- maybe that's --
16 I don't know.

17 MR. HANNA: One thing, if I could add on to
18 what Tony was saying. We have talked about the how we go
19 about determining whether a supplemental inspection would
20 be done, and a lot of the discussion thus far has involved
21 risk numbers and E to the minus five, six, whatever.

22 There's -- what we haven't talked is about the
23 second prong to our approach. It is a risk-informed
24 process, not a risk-based process. We have deterministic
25 risk -- deterministic factors that we evaluate in our

1 management directive 8.3 review -- that's the terms for
2 it -- where we go down a check list and we look for areas
3 that would concern us.

4 Say this event were to happen -- well, let's
5 say a different event were to happen. Let's say they have
6 a problem with a diesel generator. If we have reason to
7 believe that the second diesel, or if they have more than
8 one other diesel, might potentially be affected that might
9 cause us to launch and do a special inspection or
10 something more.

11 We may not know the answers to that fully when
12 this event occurs. They may not have gone through their
13 root cause analysis or, you know, whatever, or even done a
14 very short quick turn around, but those kind of factors
15 would inform us, and if we have reason to doubt or
16 question the licence -- the extended condition, amongst
17 other things, that could cause us to do a special
18 inspection or more.

19 I just wanted to share that second prong.

20 MR. MAYNARD: I would think there'd be a couple
21 of important aspects. First of all, an event like this,
22 you know, is there something going on that you need to
23 take more look at, whether you think it's a design issue
24 or you think it's operator performance, whatever.

25 As far as the safety significance of it, what I

1 think would be important is, have you found something that
2 is an initiator that you had not considered before, or is
3 it something that is occurring more frequently than what
4 was assumed in the original -- because all of these, you
5 drop anything on the control panels and you may cause a
6 transient, but that should not cause core damage.

7 But it is an initiator. And is that
8 initiator -- is that something that is quite different,
9 especially in frequency that might occur that might
10 have -- change your outcome in core damage frequency?

11 MR. HANNA: Yes, sir. And I if I could add on
12 to what you're saying, a lot of folks here today are from
13 academia. You think about equations with four or five or
14 six variables; you tweak one variable and see the effect.

15 To answer a previous question about why we
16 evaluate a single performance deficiency and only that
17 performance deficiency and look at the changing CDF or
18 LERF, it's because that's what we're doing, is essentially
19 a sensitivity analysis. We want to isolate that and look
20 at it in a vacuum to see how important it is, or not
21 important.

22 Does that sort of add on to what you're saying?

23 MR. MAYNARD: I would hope that a lot of these
24 that we do, it doesn't have a significant impact on core
25 damage, or we've got other issues to deal with here,

1 but --

2 DR. BONACA: Although you also look at repeat
3 events so that you don't just look at an event in
4 isolation. You also look at the context of how many other
5 things are happening which are of a similar nature because
6 you want to -- or you're looking at a cross-cutting issue.

7 MR. LOVELESS: That's one thing I wanted to
8 bring back up real quick, was that you were talking about
9 licensees getting different treatment in the SDP arena and
10 the action matrix arena based on the luck. We have
11 this -- the evaluation of events is just one way that we
12 inspect.

13 We have resident inspectors out there, we send
14 people from the region for various inspections. If a
15 resident inspector sees indication, or talking to people
16 says, okay, three times in the last month some chart
17 recorder's falling.

18 We may not have any major response, but he may
19 go in as part of his routine baseline inspection and
20 evaluate that and say, hey, this is falling apart because
21 of a design error and you're dropping stuff on your panels
22 that you shouldn't be, and that's a performance
23 deficiency.

24 And in that case he would take that, bring it
25 into his inspection program, find that it was more than

1 minor, put it into the SDP process, and the licensee --
2 the evaluation, if they were the exact same plant, the
3 evaluation of that and the SDP would be exactly the same
4 as the evaluation of the event that we went and looked at
5 on our special inspection at River Bend.

6 So it may make them -- the event significance
7 makes us more likely to inspect that area, but it doesn't
8 change the significance of the finding once we've
9 identified it.

10 MR. MAYNARD: We've pretty much beat this to
11 death here. I was wondering if there's some other
12 question -- or other issue. I'd hate to spend our whole
13 time on just one issue, although it is important in
14 understanding the regulatory oversight process.

15 Does somebody else have any other --

16 MR. GODY: I was going to try another bridge
17 and see if anybody jumped at it. I tried the EP bridge,
18 and it didn't work.

19 But every time we have an issue, every time
20 there's an event, licensees are required to take those
21 events or those issues and develop lessons learned and
22 train their operators or their technical staff. And
23 that's actually a requirement in our regulations, that
24 licensees' training programs capture lessons learned and
25 incorporate those into training for operators or

1 engineers.

2 And we've had a number of issues in Region IV
3 where licensees weren't particularly successful in
4 identifying -- taking issues that they learned in the
5 plant, or even at other facilities, and weren't capturing
6 them in their requalification programs.

7 And we do have a couple of examiners here;
8 you've got a couple of EP specialists and residents, and I
9 was wondering if anybody was interested in any dialogue on
10 that.

11 DR. ABDEL-KAHLIK: I would like to ask a
12 question about the component design bases inspections.

13 VOICE: Yes, sir.

14 DR. ABDEL-KAHLIK: As a part of this process,
15 I'm sure you get to look at configuration management. How
16 do you assess the adequacy of configuration management
17 protocols?

18 MR. REPLOGLE: Well, it comes down -- to be
19 honest, it comes down to instances where we think we can
20 come up with a finding that's greater than minor in
21 nature. If we're looking at configuration management for
22 a certain component, or a procedure that gives operators
23 steps they have to take to make sure that systems operate
24 properly, if those are inadequate, we take enforcement
25 actions.

1 So we walk down quite a few procedures to make
2 sure that the procedure's steps are adequate to support
3 the safety function.

4 DR. ABDEL-KAHLIK: No, I was much more
5 concerned about design changes.

6 MR. REPLOGLE: Oh, design changes?

7 DR. ABDEL-KAHLIK: Right. And configuration
8 management associated with design changes.

9 MR. REPLOGLE: That gets down to -- we find a
10 lot of things that are minor, that don't pass the more-
11 than-minor threshold. And we find a number of mistakes
12 that don't have a lot of significance. Those never get
13 documented.

14 We may tell a utility that, hey, we found 14
15 mistakes here, they're all minor, but that lends you to
16 believe you're not properly controlling this. But as far
17 as enforcement actions, we need to be able to develop some
18 tangible evidence that shows that it could be more safety
19 significant concern if it wasn't corrected.

20 DR. ABDEL-KAHLIK: But from the --

21 MR. MAYNARD: Risk management also gets looked
22 at on a number of other aspects.

23 MR. REPLOGLE: That's correct. We do 50.59s
24 and mod inspections and -- but the CDBIs look at it from
25 the beginning to where it is now.

1 MR. GODY: Right. And configuration management
2 issues really can result in weight and safety issues, and
3 that is a concern to us. So we take every opportunity to,
4 when we have an issue, or we have a failure, we take every
5 opportunity to explore that issue and that failure to
6 determine whether or not there's a configuration
7 management issue associated with it.

8 For example, if a licensee were to install
9 commercially grade dedicated diodes and a voltage
10 regulator for a generator set and those diodes were
11 manufactured with less contact surface area in the P&P
12 junctions and increased the probability of the diode
13 failing due to over current, then there's a chance that
14 you could have a decrease in the reliability of these
15 generator sets.

16 So if we see a failure like that occur in the
17 industry quite often, what we'll do is we'll inspect that
18 and we'll particular look at whether or not those
19 components were dedicated properly, whether or not there's
20 a potential common thread throughout the site, maybe those
21 diodes are used in other locations.

22 And we do look at the configuration management
23 aspects of components that might demonstrate reliability
24 issues. So that kind of gets a little bit at the -- but
25 it's not a design -- it is a design change, I mean a

1 commercially dedicated diode. And we've had examples
2 where equipment's been commercially dedicated or been
3 replaced, and we've found issues with it. And it has had
4 common cause aspects to that, and we evaluate that.

5 DR. ABDEL-KAHLIK: I mean, if you go through
6 and inspect a certain component, you're looking for a
7 design basis, the source or information.

8 MR. GODY: That's right.

9 DR. ABDEL-KAHLIK: What if you have
10 undocumented design basis for a certain console? What
11 would you do?

12 MR. REPLOGLE: Well, that could be a design
13 control violation. I'm flipping into regulatory space
14 here, but a licensee need to have a documented design
15 basis for all their equipment, and that'd be a design
16 control violation.

17 Usually there is something and in most cases
18 they have trouble finding it. And that tells us something
19 too, if they having trouble finding the information. But
20 the line in the sand is really the burden of proof is on
21 us to show that it's -- it could be significant, that it
22 could be more than minor.

23 DR. MALLETT: George, use the example out at
24 Diablo Canyon with a heat exchanger --

25 MR. REPLOGLE: I wasn't involved with that, but

1 I'll talk about it if you want me to.

2 DR. MALLETT: I think they were giving a good
3 example.

4 MR. REPLOGLE: At Diablo Canyon -- which heat
5 exchanger was that?

6 (Simultaneous discussions.)

7 MR. REPLOGLE: Yes, CAW with -- they had salt
8 water cooling. The heat exchanger was located at an
9 elevation -- it was an elevation difference that was big
10 enough between where the heat exchanger was and where the
11 discharge of the piping went back out into the ocean to
12 where it could pull a void at the heat exchanger.

13 And the licensee, what I heard is that they did
14 know about that, but they didn't think it was a problem.

15 VOICE: He's going to take it.

16 DR. MALLETT: The point I was trying to make in
17 answer to your question is, we did identify -- through
18 this team saying that's a component we want to look at
19 that could be risk significant, we did identify, and the
20 licensee identified, there wasn't enough margin in that
21 component like they thought they had, and it had to do
22 really with its location height-wise which affected the
23 flows, or could affect the flows through that heat
24 exchanger if it was needed.

25 So my point I was trying to make was that

1 individual component impacted the functionality of the
2 whole system. And so what we've found in some of our
3 inspections, like this one, licensees were many times
4 looking at components, but not in modifying them, but not
5 paying attention to the whole impact on the whole system,
6 if that makes sense, because at some point in the process,
7 this heat exchanger was moved up the hill, or in the
8 original design was moved up the hill in construction from
9 where it was designed, if that makes sense. That's what I
10 was trying to get at as an example.

11 MR. GODY: Yes, we actually have a pretty
12 straightforward example of configuration management on a
13 licensee --

14 DR. MALLET: But I thought that was
15 straightforward.

16 MR. GODY: No, this one's --

17 (General laughter.)

18 MR. GODY: We actually have somebody on the
19 panel that can talk about it.

20 Licensees are required to operate their plant
21 the way they're designed. Jim identified an issue at a
22 facility where a sign had fallen.

23 You want to talk about that a little bit?

24 MR. DRAKE: This was a component design basis
25 inspection at the SONGS power plant. Their condensate

1 storage tank was not seismically qualified, so they built
2 a berm around it that was seismically qualified to contain
3 the water. And then this berm had a sump in it that would
4 allow them to use that water to continue cooling the plant
5 down if there was an earthquake and they lost offsite
6 power.

7 But they weren't controlling the bermed-in
8 area as a form material exclusion area, and as a result
9 they had some radiation signs and other debris material
10 that were in that bermed area that was large enough to
11 cover the sump grate, so it could have cut off that supply
12 of water.

13 That was identified during the component design
14 basis inspection when we were doing walk-throughs.

15 MR. MAYNARD: Was that their safety related
16 source of condensate?

17 MR. DRAKE: It was a back-up to that, yes; it
18 was part of their safety related water. They had two
19 condensate storage tanks. One was in a seismically
20 qualified tank, and that was enough to get them started.

21 But in order to cool all the way down, they had
22 to have this second source of water. And so it was
23 necessary for cooling the plant completely down, they had
24 to be able to access that water. But because of the
25 design of the sump and their failure to control that area

1 of form material exclusion, they could have potentially
2 lost the ability --

3 MR. WARNICK: This is just an open area?

4 VOICE: It's open to atmosphere.

5 MR. DRAKE: Yes, and then they put radiation
6 signs in there to block off areas, or to rope off areas
7 where they had a problem with, you know, radiation. So
8 the material was down there and it could have blocked the
9 sump.

10 MR. MAYNARD: Eating into your time here for
11 some closing comments, I'd just say if there's any other
12 burning question that any of the members have? I think
13 it's been a good discussion. We spent a lot of time on
14 one item, but I think we explored many aspects of that,
15 which I think covered a number of other issues.

16 So with that, I'd like to turn it back over to
17 Dr. Mallett for some comments here.

18 DR. MALLETT: At the risk of expanding this
19 beyond what it should be, I'd like them to ask -- answer
20 this question to you all. Is -- with the reactor
21 oversight process, what would you change if you had one
22 choice to change? I thought that might give you some
23 insights. So nobody wants to jump out?

24 VOICE: You're likely to get nine different
25 answers.

1 DR. MALLETT: Kelly, you want to jump up --

2 MR. MAYNARD: We're used to that.

3 MR. CLAYTON: Tough question. I think it would
4 be nice to add more human performance aspects into the
5 SDP. We do have trouble getting our hands around operator
6 performance issues, and they seem to have increased. And
7 so that would be my request as an examiner.

8 DR. APOSTOLAKIS: You mean more than the
9 components and all that stuff?

10 MR. CLAYTON: Absolutely.

11 DR. APOSTOLAKIS: But why? I mean, that seems
12 to be detailed enough. Like give me an example of
13 something that, in your opinion, is not covered as well by
14 the SDP as it should.

15 DR. MALLETT: You took the microphone.

16 MR. CLAYTON: It was given to --

17 VOICE: Kelly, if I could --

18 DR. APOSTOLAKIS: What is the difficulty of it?
19 I don't want to put you on the spot, although I enjoy
20 doing it, but what is the difficulty? I mean, you must
21 have something in mind when you say --

22 MR. CLAYTON: Well, let me give you an example.
23 In SDP space, when we do risk analysis, there is a
24 probability during certain streams of events that an
25 operator will take a certain action to shut a valve or

1 open a valve, or whatever, and that gets a certain value,
2 and that goes in these tables that the SRAs use, and so we
3 go to a facility where their performance has been
4 demonstrated to be poor, they repeatedly have reactivity
5 anomalies. And a good example of that is the SONGS
6 facility; they've had many of those in the last year.

7 And so the way that you get at it sometimes,
8 the performance aspect, the human performance errors, is
9 by modifying those values in the risk tables to downgrade
10 their credit, if you will, on certain actions during those
11 events.

12 And I would like to see more of a tool that we
13 could use on the front end of things, where we could run
14 it -- we don't have a SDP flow chart right now for just
15 human performance in general. We have to get through
16 those events, through a 41500 inspection or an SAT process
17 inspection where we look at an operator, their history of
18 making a mistake on something.

19 Sometimes we get the operator licensing folks
20 at headquarters involved on the human performance aspects
21 of the board, how the board was laid out, and is this
22 switch in a bad place where it could be bumped all the
23 time, things like that. So it gets really complicated.

24 But what we would like to have, or what I would
25 like to have, is a tool, an SDP tool, that you jump with

1 operator issues and that's what you're screening, you
2 know, up front, and --

3 DR. APOSTOLAKIS: Something simpler, in other
4 words?

5 MR. CLAYTON: Exactly.

6 DR. APOSTOLAKIS: What's your overall opinion
7 of SPAR-H?

8 MR. CLAYTON: I'm not familiar with that,
9 really. I'm not a risk analyst; I'm an examiner.

10 DR. APOSTOLAKIS: But you have used it though,
11 haven't you? You're using the notebook. Right?

12 MR. CLAYTON: We do use the notebooks, but not
13 as much as the inspectors do. The examiners, we use it
14 when we're on inspections, but -- and I'm not as
15 proficient with it as an SRA, to answer the question.

16 MR. GODY: Yes, where operator licensing uses
17 the risk informed notebooks for -- and actually the PRA
18 for -- is to identify what the risk-significant operator
19 actions are, and we make sure that the operator license
20 exams are risk informed by having a sampling of those
21 risk-significant operator actions.

22 Now, if I was going to change something with
23 the ROP --

24 DR. MALLET: Well, we didn't ask you about --

25 MR. GODY: I'm not sure I want to do this. If

1 I were to change something with the ROP, what I would do
2 is I would bring -- I would revisit the enforcement policy
3 and compare it to our deterministic and quantitative risk
4 analysis to make sure that the enforcement policy, the
5 traditional enforcement policy, lines up with the SDP
6 more. Sometimes you end up -- and you question whether or
7 not you're in the right place.

8 DR. APOSTOLAKIS: So you would risk inform the
9 enforcement policy?

10 MR. GODY: At least make sure that, you know, a
11 severe level 3 that would be handled under the enforcement
12 policy correlates to weight in the SDP, and not agreeing,
13 you know, because it confuses licensees if you issue them
14 a severe level 3 violation and if it hadn't met the
15 criteria if you were using traditional enforcement they
16 would have gotten a green.

17 It doesn't make sense. So that's an area that
18 I would spend a little time in.

19 DR. MALLETT: John?

20 MR. HANNA: Yes. Two different areas. One,
21 I -- Tony didn't mention during my bio that I come from a
22 biopsychology -- that was like my specialty -- background,
23 aside from mechanical engineering, at Georgia Tech, and
24 one thing that's always bothered me is the fact that
25 there's not uniformity in the definitions of human

1 performance.

2 You have the NUREG-1020 or -- I'm trying to
3 remember that NUREG -- I'm looking over at operator
4 licensing folks.

5 MR. CANIANO: 1021.

6 MR. HANNA: 1021. Thank you.

7 And then there was all these different criteria
8 definitions, so there's no uniformity between the industry
9 and us on these various measures.

10 The other thing is sometimes the risk analysts
11 get into -- like they give us a number on a core damage
12 frequency, and I'm always wondering what the band width is
13 on this. I think of a distribution curve, or possibly --
14 it'd be nicer to know what certainty we're talking about.

15 Now, they end up usually quite often doing
16 sensitivity analyses to justify the phase 3 that they come
17 up with. But it would be nice for inspectors, and
18 possibly make it more scrutable to the public, get a
19 number you can see how wide that number is which speaks to
20 our uncertainty about it. It would be graphical; it would
21 be scrutable.

22 DR. APOSTOLAKIS: Have you talked the
23 headquarters guys about this?

24 MR. HANNA: No.

25 DR. APOSTOLAKIS: Because the message we're

1 getting from them is that distributions would confuse
2 people.

3 MR. HANNA: Could be. That's -- no, I didn't
4 talk --

5 DR. APOSTOLAKIS: Well, that's --

6 MR. HANNA: -- to headquarters. This --

7 DR. APOSTOLAKIS: -- I'm glad you said --

8 MR. HANNA: -- is just my little two cents in a
9 vacuum.

10 MR. WARNICK: All right. I guess this is a
11 difficult situation for me, since I just spent time
12 earlier telling you how successful the ROP has been in a
13 case study from Palo Verde.

14 But something that I needed a change for were
15 resources for inspection. We've been allowed N inspectors
16 at Palo Verde; that equates to three inspectors. But I've
17 needed additional help for some time, and actually we
18 finally got approval. Bruce helped us, up through Jim
19 Dyer to get N+1. We actually have an additional inspector
20 coming out in September, which will help greatly with the
21 resources.

22 And additionally I'd like to say that -- I
23 talked earlier about how the revised oversight process was
24 successful in us directing our regulatory resources to
25 oversee Palo Verde in the way that we felt was needed.

1 However, as Bruce kind of mentioned earlier in my
2 discussion, I felt the need for more regulatory oversight
3 earlier than the process allowed us to provide.

4 I saw a lot of indicators early on, was uneasy
5 about the performance at Palo Verde. Yes, we still had to
6 go through the process to eventually get the licensee to
7 call them forward based on their performance, where,
8 again, I felt that this level of oversight was needed
9 since they were struggling with correcting their problems
10 and implementing the plans that they developed.

11 DR. SHACK: If you had the new safety-culture
12 thing in place when all this started, would that have made
13 a difference?

14 MR. WARNICK: Well, the new safety-culture
15 piece would have been done, I guess, to a certain extent
16 with the 95002 inspection. A licensee would have known
17 that that was a piece of this, so they obviously would
18 have taken actions to address that.

19 They did -- getting to your question, they did
20 do some safety-culture type investigations back at that
21 time period, however. In fact, they had the same group
22 that came in recently come into Palo Verde in the 2004-
23 2005 time frame, Synergy, to do some safety-culture
24 assessments.

25 We did -- the results out of that, as far as

1 the licensee was concerned, was that it was relatively
2 positive. However, if you looked at it real closely, it
3 caused us to have additional concerns.

4 To a certain extent it would have allowed us to
5 have additional concerns, but a licensee was looking at it
6 and still they failed to correct the problems that they
7 had out there to the extent where they are currently.

8 MR. LOVELESS: David Loveless again. My
9 biggest concern with the ROP as it exists now is that the
10 SDP continues to expand in its use of resources with very
11 little increase in the benefits that we've been getting
12 from it.

13 I can show examples where we've spent 1,000
14 plus man hours to determine whether something is either
15 green or white. We have examples of where licensees have
16 spent \$3 million in a test because they didn't want to
17 indicate white on their -- in the matrix.

18 We are being pushed by the licensee quite
19 often, but also from our program offices, to get a more
20 and more precise number in our SDP to justify going over
21 the green threshold, and in most of those cases it's
22 because of push back from the licensees.

23 But the root cause, in my opinion, is that we
24 haven't gone out as an agency and set bounds and said, you
25 know, the primary reason for making a green/white decision

1 is so that we can allocate our resources, and we're
2 allocating 40 inspection hours on a 95001.

3 How can we justify spending 2,000 man hours and
4 a licensee spending \$3 million to decide whether we expend
5 40 hours of resources in the field? So that's where we
6 need to improve.

7 DR. MALLETT: Anyone else? Jim?

8 MR. SHUKLA: Yes. Just a minute. I have a
9 question --

10 DR. MALLETT: We've got a quick question here.

11 MR. SHUKLA: Yes, my name is Girija Shukla.
12 I'm the senior program manager for the ACRS. I was very
13 impressed this morning to hear about the knowledge
14 management and all its sharing, and I was wondering
15 whether this kind of information is relevant to the
16 industry, and if there is any way to monitor their use.

17 Like Greg said, that all the indications of
18 poor performance we couldn't deal with them because we had
19 no program, we didn't put out a program at that time. But
20 if we had some way to share this information with the
21 licensee, they can take some action, put those in the
22 corrective action programs and so forth so other people
23 don't become complacent to something like this.

24 So is there any way we can share our knowledge,
25 a transfer mechanism like, you know, newsletters or

1 whatever we share with each other with the industry and
2 somehow we could monitor whether the licensees are using
3 those tools would be much beneficial.

4 DR. MALLET: I'll start out on that. We have
5 been -- that's a very good point, and we have been using
6 various mechanisms to share this information.

7 One is, as the senior leaders, Dwight
8 Chamberlain and myself, and the other senior managers in
9 the region, meet with the site plant managers at least
10 once, sometimes twice a year, in Region IV. We meet with
11 the site vice presidents at least twice a year.

12 We also meet with the Regulatory Affairs
13 managers, and we bring up these issues with them. And
14 they -- just a forum similar to this, for about a half a
15 day, and they bring up issues with us as well. So that's
16 a great forum where things are shared.

17 I think also the residents do an excellent job
18 of sharing these things in their meetings they have with
19 the site managers and other members of the licensee's team
20 at the site. Licensees share things in their operational
21 experience program through INPO.

22 They have asked us to come up with an
23 operational experience program where we share inspection
24 results, because if you're recognized on the reactor
25 oversight process -- we changed to not put much detail in

1 the inspection reports, so they don't get a lot of these
2 observations any more to share early on.

3 And that's something they've asked us for at
4 least the past couple of years now, is there a way we can
5 share operational experience from inspection reports. And
6 we've kicked it around but haven't done much in that area.
7 But I can tell you, I knew their regulatory affairs
8 manager shared.

9 So I don't know if that answers your question,
10 Girija, but I think it's very important --

11 MR. LOVELESS: Right. The one -

12 DR. MALLETT: -- those forums that we do, so.

13 MR. LOVELESS: -- one thing I would add to that
14 is that we do have counterpart meetings. For example, in
15 operating licensing, west train, we actually about every
16 six months get together and talk about issues, talk about
17 lessons learned from exams and inspections findings. We
18 have EP counterpart meetings; we just had the NEI
19 counterpart meeting in New Orleans. We have RUG meetings
20 where we talk about plant issues. So we have very --
21 numerous meetings to discuss about issues and lessons
22 learned.

23 DR. SHACK: Just a quick -- back to Mr.
24 Loveless's point. You know, what would you do? I mean,
25 you're trying to draw a sharp boundary with uncertain

1 values, and, you know, to a certain extent -- I mean,
2 you're just going to have live with that. Is that --
3 you're just saying that you realize that's true and stop
4 the analysis rather than trying to flesh it out?

5 MR. LOVELESS: That's pretty much what I'm
6 saying. We have invested a lot of time and effort into
7 some tools, and we could argue the strength and weaknesses
8 of those tools. But at some point we could go out as an
9 agency and say, Our phase 2 notebooks have been developed,
10 and for all components modeled within those notebooks, if
11 you have a component out of service, that's failed, and we
12 follow the phase 2 notebook and it comes up white, that's
13 the answer.

14 If you don't like the tool right now, let's
15 talk about it up front why the tool should be improved.
16 But that is our tool, that's how we're going to do SDP.
17 And then on our yellow and red findings, the ones that are
18 much more significant, that have much more of an impact to
19 licensees, then we have the broader licensee inputs, and
20 it's worth our time and effort to spend more time, to try
21 to analyze those additional risk factors.

22 DR. MALLETT: Yes, I would add to that I think
23 it's very important between us and the licensee that we
24 come to some alignment on the assumptions that are made in
25 the analysis, because those can make a big difference one

1 way or the other.

2 But many times where the answer comes out very
3 clear, we don't have a problem. It's that interface, the
4 green/white interface, is where we have the issues now.
5 And so we embarked upon -- Dwight Chamberlain did a study,
6 as I indicated earlier, to map out the process.

7 And what we embarked upon was there has to be a
8 decision made, right or wrong, these are the assumptions
9 we're going to use, these are the differences between what
10 the licensee came up with and we came up with, here's our
11 answer.

12 And many times it comes out -- and you've seen
13 me draw this before -- it comes out a spectral analysis
14 of -- scatter-plot, if you will, all around that
15 interface. And many times you have to say, well, is it
16 more likely, what's the best answer than not that it's
17 white or is it green.

18 And that is a problem, but I think David's
19 right. At some point you have to say enough is enough,
20 it's not longer going to be a research project, and we're
21 done with it.

22 MR. MAYNARD: Yes, and I don't disagree with
23 that. I think you -- I can understand why it's important
24 in some cases. It's not just a matter of how many
25 resources are put on an inspection because when something

1 does cross the line, then that also sets up -- it's
2 another thing closer to a degraded cornerstone or
3 something like that.

4 So it has other implications, and I think
5 you'll always get some push back from the industry. And I
6 don't think that's bad. I think that it's good for the
7 regulator and the industry to discuss these things and to
8 push those up. I do agree at some point somebody's got to
9 make a decision and say, this is what we're going to do.

10 But it does go beyond just whether or not we
11 put some additional resources on an inspection or not. It
12 has other implications; that's why it's important to have
13 some good basis for it.

14 DR. MALLETT: I agree totally. It has
15 implications for the regulator and the licensee, much,
16 much far beyond resources.

17 DR. SHACK: Let me just come back to the tools
18 that you use. I mean, I thought the SRA would be off
19 looking at this thing with SPAR-H, and the inspector would
20 be using the notebooks. Are most of the analyses really
21 done with the notebooks and it stops there?

22 MR. LOVELESS: No, none of them are.

23 DR. SHACK: None of them are.

24 MR. LOVELESS: None of them are. And -- but --
25 you know, as an example, our -- the -- what we'll accept

1 and how much information we analyze and to what level we
2 analyze it is changing, as opposed to getting to a point
3 where we say, okay, these are things that are acceptable
4 for the analysis, these are things that aren't.

5 We recently had an issue where we spent a large
6 amount of time trying to decide whether a facility that
7 had a diesel generator fail, and they came in and said,
8 well, we could have recovered this diesel generator.

9 How could they have? And I'm going to give as
10 fair an assessment as I can, they would have had to send
11 out an INC team, they would have had to determine that a
12 voltage regulator had failed, then they would have had to
13 determine that a voltage regulator failed in a very
14 specific way.

15 Then engineers would have had to determine
16 that, hey, with the voltage regulator failing this way, we
17 could manually bring this machine up using a method we've
18 never done, we don't have procedures for, and then having
19 the operators, with this unique evolution, bringing this
20 machine up.

21 Under my way of doing business, we would never
22 have allowed that entire evaluation. We would have said,
23 this is beyond what we're going to consider as valid risk,
24 when you're comparing it with a PRA that's not modeled
25 anywhere near that level, because every time you model

1 to -- something to a different level, you artificially
2 change its significance.

3 And yet we were directed and spent many, many
4 hours trying to decide what's the probability that the
5 licensee could have done this action. And --

6 DR. MALLET: Let me add to that, David.
7 This is a case that's currently being discussed, so I want
8 to be careful. But I can tell you that I think it was
9 good in this case because it has some implications for the
10 licensee to go a little bit further. But what we have
11 been trying to do lately is identify where the differences
12 are and make a decision.

13 In the past, you'll find back a couple of years
14 ago, we were not doing that, and these might go on for six
15 months, some of them. Now we're making that decision
16 before we get to the 90-day mark. And I think that's
17 healthy. And it does -- there are different views on
18 them. I think that's healthy to have a consensus process.

19 VOICE: Since you're still --

20 DR. MALLET: Well, let me try and shorten up a
21 summary here, then. I will say this, I think that -- I
22 would add one thing. The issue of the 95003 in safety
23 culture, one of the things we're tasked to do in the Palo
24 Verde case, because it's our first case of reviewing with
25 this new procedure, is to look at our own procedures to

1 see do we have the right guidance out there, do we have
2 the right things we're looking at?

3 So we will feedback to determine is this the
4 right look at safety culture, is this the right way to
5 look at it.

6 I would summarize today by saying we did try to
7 provide you a spectrum of individuals to talk to and
8 present their views on our oversight of reactors programs
9 in the regional office. I think we've done that. We
10 tried to use case studies. I know it's difficult
11 sometimes to talk about those, but we try to help you in
12 that area.

13 I would encourage you to give us feedback if
14 that's the right thing to do, because the next time you
15 meet with another region they'll pattern off of what we
16 did.

17 And then I would add this at the end, is the
18 program identifying the right issues? I think that's
19 dependent upon three things, you can maybe add to this
20 list, but one is that we revisit the program every year,
21 and we build into this reactor oversight process doing
22 that.

23 My worry, besides not turning over every
24 rock -- that's one of my worries I said earlier today --
25 is that we'll stop that revisiting of the program and

1 think we've reach Mecca. I think that's one key item to
2 this program, to make sure we keep revisiting it.

3 You help that by coming and asking us these
4 things. I can guarantee you we'll discuss your visit
5 after you leave for what did we learn from that ourselves.

6 DR. SHACK: But there is a formal feedback
7 mechanism to this.

8 DR. MALLETT: There definitely is a formal
9 feedback mechanism that has --

10 DR. SHACK: You assume that it's going to
11 disappear?

12 DR. MALLETT: No.

13 DR. SHACK: No.

14 DR. MALLETT: That has pros and cons to it.
15 But I do know in the previous system, over a period of
16 time, that change in the process and looking at it faded
17 away. And so I'm hoping that we don't fade it away in
18 this process.

19 I also think it -- another key to success are
20 the people you see sitting around this table and in this
21 room, and keeping their expertise, because I think that's
22 a key part of any process, to knowing what to look for.

23 And then last I'll make my plug again for
24 turning over every rock. I think we have to continue to
25 be diligent in the process.

1 And I want to thank all the people today. I
2 think you all did an outstanding job, and I think you gave
3 them -- I hope we gave you the insights you were looking
4 for.

5 MR. MAYNARD: Well, good. Well, thank you very
6 much. And before I ask the members for some comments
7 there, I would like to open just real briefly to if
8 there's anyone from the public that has a comment they'd
9 like to make, or anything, I'd give an opportunity here.

10 (No response.)

11 MR. MAYNARD: Give the public one minute and
12 the NRC all day.

13 All right. With that I'd like to just kind of
14 go down the line --

15 DR. WALLIS: Well --

16 MR. MAYNARD: -- and see if you have any
17 comments.

18 DR. WALLIS: -- I would say I liked the case
19 study approach when the question was asked, but I've heard
20 it from the other regions. It's good to hear stories of
21 what happened and how the region responded, how the
22 licensee responded, how things were resolved or not
23 resolved, and what we learned from it.

24 I like the case study approach. I found those
25 were useful this time, I found them useful before when we

1 visited regions. So that would be my comment to take
2 away.

3 MR. MAYNARD: George?

4 DR. APOSTOLAKIS: Well, I liked the whole
5 meeting. I was very impressed by your presentations. I
6 think we have top people here and they understand the
7 methods and what the agency is doing. So I was very happy
8 with this meeting. And I do like the case studies very
9 much; I enjoy those.

10 MR. MAYNARD: Bill?

11 DR. SHACK: Again, I thought it was a very good
12 meeting. I guess, you know, I like the case studies. I'm
13 intrigued by SDP, which was always, you know, one of the
14 final places we end up hearing -- next time I'd like a
15 more detailed -- you know, really go through a case study
16 with an SDP, and let me see how it goes from the inspector
17 to the SRA, and maybe back and forth. I'm thinking that
18 that I would find that valuable.

19 DR. MALLET: I think we arrange that if we
20 have about two, three days to --

21 DR. SHACK: Well, I realize that may take up a
22 chunk of time, but I think it could be worth it.

23 MR. CANIANO: Dr. Mallett has mentioned that we
24 did have a study. It took me two months to go through
25 that.

1 DR. SHACK: But see you've got it all worked
2 out now.

3 DR. BONACA: I can only repeat what my
4 colleague said. That was a great meeting, I think it was
5 well informed, a big effort, real hard to put together.
6 It was a very well prepared presentation. I like the case
7 studies.

8 I wish we had, by now, more experience of the
9 improvements of the safety culture and see, you know, but
10 still you have to have experience on that, and time will
11 tell.

12 In general I thank you all for the -- for an
13 outstanding presentation.

14 DR. CORRADINI: I guess I'll lend my voice to
15 thanking you for your time and all that we've learned.
16 I'm new to the committee, so a lot of this I was learning
17 for the first time, relative to the inspections and the
18 procedures.

19 The one thing I guess that I would say -- I'm
20 not going to say anything about the case study, or else
21 that would be too unanimous -- no, I thought it was
22 good -- is that from a knowledge transfer, a knowledge
23 management standpoint, I was interested in that primarily
24 because I'm more -- I'm, to a large extent, interested in
25 how the history of how the agency is changing with a whole

1 new set of people coming in and potentially a whole new
2 set of plants starting up.

3 And so that's why I was quite interested in a
4 lot of what you're doing now. And I appreciate the time
5 you've given this. Thank you.

6 DR. ABDEL-KAHLIK: Yes, I'd like to reiterate
7 what my colleagues have already said. This has been a
8 very informative and very well organized and thought out
9 meeting. I would add my thanks to those expressed by my
10 colleagues for the time and effort you've devoted to this
11 presentation today.

12 MR. MAYNARD: Well, I do appreciate everybody's
13 involvement in the meeting. Relative to case studies, I
14 do think that's a good approach. I will say I think we
15 need to be a little careful sometimes, and we were talking
16 fairly freely. This is a public meeting, and some of the
17 comments that we've made that aren't really part of the
18 official record I think could be interpreted by some maybe
19 inappropriately.

20 I think we have to be a little careful in how
21 we -- or what we say on some of our opinions of what went
22 on in some of these, and try to stick to what happened and
23 how did that really affect the regulatory oversight
24 process and stuff, because, you know, people will read the
25 minutes from these meetings and read things, and certain

1 things probably be taken out of context could create
2 both -- problems for both the regulator and for licensees
3 and stuff, maybe unnecessarily so.

4 I do think it's a good process and I think it's
5 a good way to get into how the process works. I would
6 offer some caution just how -- you know, what we say about
7 some personal opinions on some things in a public meeting,
8 they're -- may or may not be valid, especially where we
9 don't provide an opportunity for the licensee to come in
10 and maybe present their perspective on some of the things.

11 I don't think there would be much disagreement
12 on the facts of what happened and stuff. There would be
13 some, but, you know, I think that some of the other stuff
14 that gets filled in there that might -- I was very
15 impressed with just the overall interaction among the
16 Region IV staff. I didn't see any hesitancy in anybody
17 speaking up, of correcting somebody, if they had
18 additional information or whatever.

19 I think that shows good teamwork and respect
20 for each other that I think is critical to the success of
21 an organization, to feel that for you to be able to talk
22 and provide your input. So I was impressed with that, and
23 commend you on that. And I think that reflects very
24 positively upon your overall staff here. So I was
25 impressed with that.

1 I'd like to say I really appreciate the
2 hospitality, and I think you met all of our needs and
3 everything here. I think that everybody got what they
4 wanted. Had to push some people along at times here, but,
5 you know, a number of these things we could probably talk
6 for days on.

7 With that, if there's no last-minute comments,
8 which I won't give more than a half a second for, I'd like
9 to go ahead and adjourn the meeting and call it to a
10 close. So thank you very much.

11 (Whereupon, at 4:10 p.m., the meeting was
12 concluded.)

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CERTIFICATE

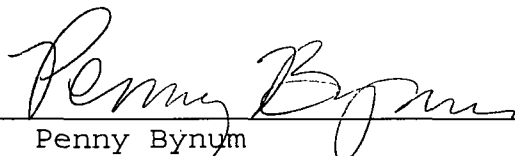
This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

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
Official Reporter
Neal R. Gross & Co., Inc.



U.S. NRC

United States Nuclear Regulatory Commission

Protecting people and the environment



Recruitment & Retention Best Practices Booklet for Supervisors

Office of Human Resources

***Cover Photo:
Recent Nuclear Safety Professional Development
(NSPDP) Graduating Class***

The Purpose of this Booklet

The purpose of this booklet is to inform supervisors about regional best practices in recruiting a high quality and diverse staff and retaining them! In today's highly dynamic job market, applying these practices will help new supervisors to achieve this important goal.

Recruitment Best Practices – Looking in the Right Places for the Right People

How does an organization best attract qualified applicants? This challenge extends well beyond the immediate workplace, calling us to hire with an eye toward future needs, rather than toward the skill sets that are sufficient today.

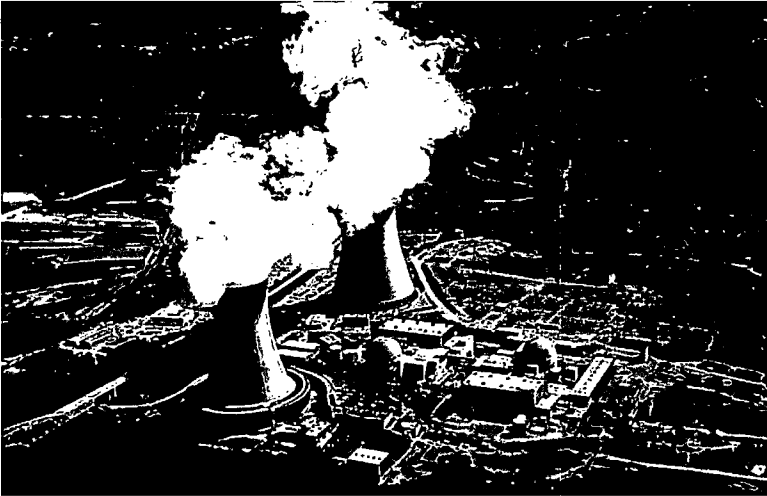
Winning the war on talent in today's job market.

Emphasis is on forecasting future vacancies and developing a proactive, targeted recruitment strategy to fill them, while keeping in mind that new generations of workers call for new recruiting strategies.

Thus, the following best practices are highlighted:

- Use agencywide vacancy announcements for general engineers/scientists for both the Nuclear Safety Professional Development Program (NSPDP) program and experienced professionals.
- Build coalitions among Professional Associations (e.g., Society for Women Engineers, National Society of Black Engineers, Society for Hispanic Professional Engineers, Asian Pacific American Conference, Service Academy Career Conference), and colleges and universities with diverse populations—including Veteran groups and groups representing individuals with disabilities.
- Maximize the use of paid ads and/or free job listings in:
 - Appropriate professional journals, particularly those with both an engineering/physical science and a minority population focus
 - Newspapers in key labor market areas (near nuclear facilities, shipyards)
 - Online job bulletin boards, particularly those offered by appropriate professional societies

- Actively participate and support the agency's recruitment efforts to achieve a high quality, diverse workforce.
- Support "University Champions"—these are managers who work with selected universities to strengthen and develop relationships with University faculty, deans, placement officers, and diverse student populations.



Beaver Valley Power Plant

- Effectively market of NRC's "Best Places to Work" status as outlined in <http://www.bestplacetowork.org>.
- Learn about "referral awards" by encouraging NRC staff to locate and shepherd successful candidate placements. See <http://www.internal.nrc.gov/announcements/items/2167-policy--.html>.
- Ensure diverse organizations know about NRC vacancies via NRCareers.
- Volunteer to participate in outreach via presentations at professional conferences. Also, participate in "meet and greet" sessions conducted to support recruitment efforts.
- Use the agency Strategic Workforce Planning (SWP) tools to identify current, emerging, and future skill gaps.
- Volunteer to participate in local Federal Executive Boards as an additional communications vehicle for publicizing current NRC vacancies.

- Work with your servicing HR office to learn about the various recruitment tools available, such as:
 - Approval of credit for annual leave for directly-related private sector and/or military work experience for external applicants
 - The salary exception process for recruitment of highly qualified candidates
 - Flexiplace opportunities
 - Recruitment and relocation incentives
 - Payment of travel and transportation expenses for Student Programs
 - Solicitations of Interest
 - Network Announcements
 - Use of the agencywide vacancy announcement for general engineers/scientists for both the NSPDP program and experienced professionals



OPM Director Linda Springer and OHR Director Jim McDermott

Retention – Keeping the Right People in the Right Places

Human capital is the most valuable resource of any organization. As a result, the departure of an experienced employee is expensive in terms of recruiting, screening, hiring, and training a replacement.

It is even more costly in terms of the loss of experience, stability, and continuity. These losses are less tangible. Nonetheless, they deplete critical resources.

Knowing why employees leave is critical to reducing turnover, but just as important is finding out why others stay—which not only provides valuable information, but also sends a message to employees that the NRC is concerned about their well-being.

Job satisfaction (and therefore, retention) goes hand-in-hand with career development (and therefore, succession), emphasis is placed on assuring that employees are continually growing.

Since one's immediate supervisor is a key factor in turnover, attention is also devoted to promoting and developing effective supervisors.

However, everyone is not equally interested in

becoming the next Chairperson, especially true among the new workforce. We must understand what "disincentives" make promotion unattractive and what can be done to improve the situation.

Succession planning is critical and is viewed as a comprehensive process that involves "marketing" promotional opportunities, as well as coaching, and other career development techniques designed to produce a qualified pool of candidates who are well-prepared to compete for upcoming supervisory, managerial, or leadership vacancies.

Based on the concept that job satisfaction (and therefore, retention) goes hand-in-hand with career development (and therefore, succession), emphasis is placed on assuring that employees are continually growing, stretching, learning, and being challenged.

Also, workplace diversity (including multigenerational) promotes job satisfaction because the contributions of all employees are recognized and valued.

As supervisors, ensure new employees are cared for and encouraged—not abandoned. New employees should be assigned a peer sponsor by their supervisor.

The peer sponsor assists the new employee in:

- making the transition into the NRC;
- connecting with the correct contacts;
- enrolling in training; and
- completing the requirements of inspector qualification and appropriate administrative programs.

As a supervisor you must ensure new employees are given meaningful work.

Consider assigning new employees into a work group and monitor the progress of new employees towards meeting inspector qualifications.

Ensure the group meets regularly with the new employees to discuss their progress through the qualifications program, and identify any issues, problems, or concerns of the employees.



Braidwood "Meet and Greet"

Keep senior management (e.g., Regional Administrator and/or Deputy Regional Administrator) involved.

Suggest that you and senior management hold regular meetings with new staff to get to know them, provide for open discussion, learn about the staff and encourage them to share their perspectives, and solicit feedback on their experiences as new NRC employees.

***No stable
business could
run efficiently
with continuous
attrition.***

Seek out training and assistance to enhance your supervisory skills and build a teaming environment.

Recognize that many studies and books identify a key reason people leave organizations is because of their relationship with their supervisors.

Encourage employees to seek out rotational assignments and details

internal/external to the region and at headquarters to enhance their knowledge and skills.

Encourage employee details. Employees gain more connection (both technical and administrative staff) when detailed to another part of the organization and serve on a variety of task groups and teams addressing many issues currently facing the NRC.

Promote/support continuing education for employees, in both technical and administrative positions, at various grade levels, in programs at levels from associates to masters.

Consider using the Student Loan Repayment program and retention incentives as effective retention tools.

Additional Tools and Links

HR Staff Contacts: <http://www.internal.nrc.gov/HR/contacts.html>

Professional Development Center Training Link: <http://papaya.nrc.gov/Training/home.cfm>

Management Toolbox: <http://papaya.nrc.gov/swp/home/MgrsToolbox.pdf>

Some Professional Organization Links

National Association of Hispanic Federal Executives:
<http://www.nahfe.org/>

Society of Hispanic Professional Engineers
<http://oneshpe.shpe.org/wps/portal/national>

Society of Women Engineers:
http://www.swe.org/stellent/idcplg?IdcService=SS_GET_PAGE&nodId=5

American Indian Science and Engineering Society:
<http://www.aises.org/>

National Society of Black Engineers: <http://national.nsbe.org/>

Federal Asian Pacific American Council: <http://www.fapac.org/>

Contacts

Director, Office of Human Resources: 301-492-2076

Deputy Director, Office of Human Resources: 301-492-2076

Chief, Human Resources Services and Operations: 301-492-2220

Region I HR Team Leader: 610-337-5141

Region II HR Team Leader: 404-562-4842

Region III HR Team Leader: 630-829-9517

Region IV HR Team Leader: 817-860-8281





June 2007

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
Jamilia Perry, ACRS Staff
Girija Shukla, ACRS Staff

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. 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 Waiker, Senior Project Engineer
Greg Warnick, Senior Resident Inspector
Joseph L. Lopez, Human Resources Management Specialist
James F. Drake, Operations Engineer
Paul J. Eikmann, Emergency Preparedness Analyst

Office of NRR Staff

F. Paul Bonnett, Senior Reactor Analyst

Members of the Public

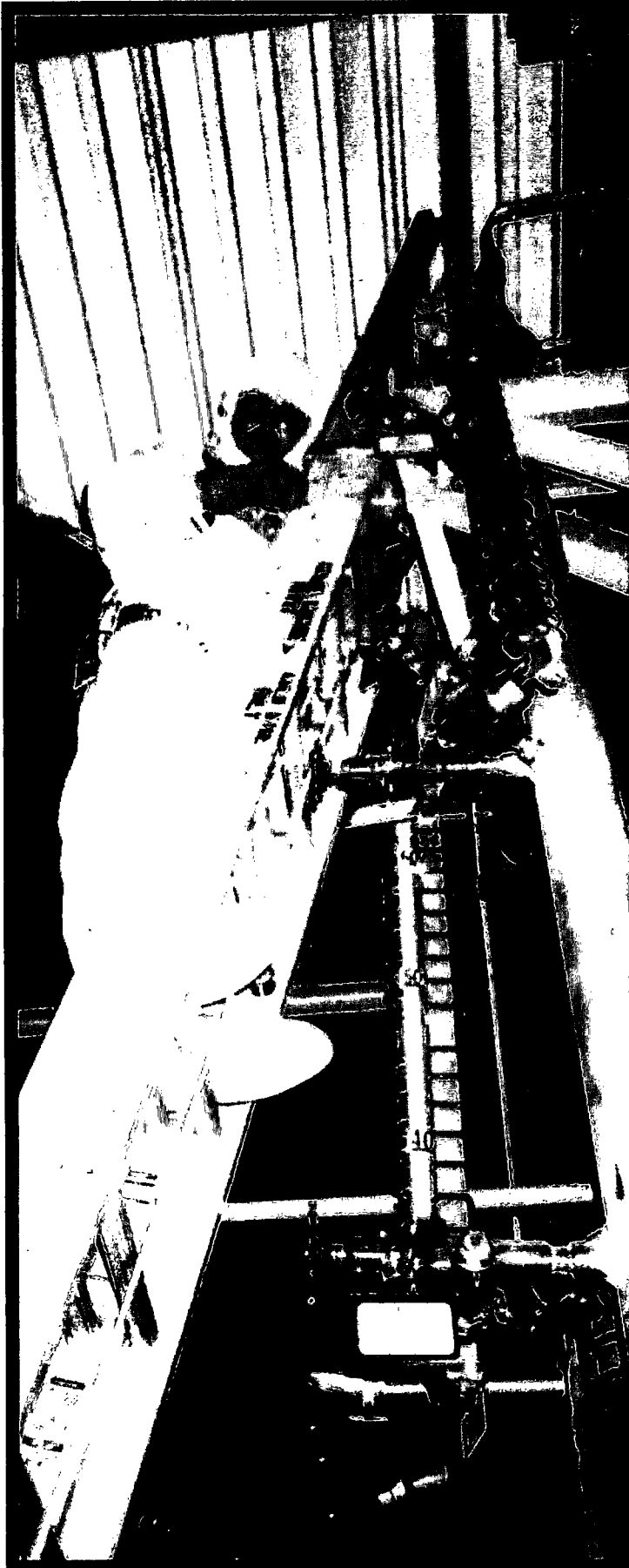
Carl Corbin, STARS Regulatory Affairs, Luminant Power, Comanche Peak
Fred Madden, Director, Oversight and Regulatory Affairs, Luminant Power, Comanche Peak
Michael McBrearty, Nuclear Regulatory Affairs Division, San Onofre Nuclear Generating Station

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	All Assessment Inputs (Performance Indicators (PIs) and Inspection Findings) Green. Cornerstone Objectives Fully Met.	One or Two White Inputs (in different Cornerstones) in a Strategic Performance Area. Cornerstone Objectives Fully Met.	One Degraded Cornerstone, 2 White Inputs or 1 Yellow Input (of any 3 White Inputs) in a Strategic Performance Area. Cornerstone Objectives Met with Moderate Degradation in Safety Performance.	Repetitive Degraded Cornerstone, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or 1 Red Input. Cornerstone Objectives Met with Longstanding Issues or Significant Degradation in Safety Performance.	Overall Unacceptable Performance. Plants Not Permitted to Operate Within this Band. Unacceptable Margin to Safety.	Plants in a shutdown condition with performance problems placed under the IMC 0350 process.	
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

NOTES

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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-

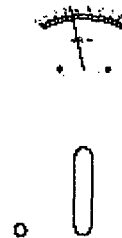
significant maintenance or modifications and verify that the clearance tags have been properly hung by comparing the information on the tags with the configuration of the equipment. (NOTE: DO NOT manipulate equipment! Verify equipment configuration by visual observation or seek the assistance of a plant 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.



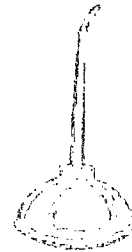
Welds: Be aware of the potential impact of fatigue on piping welds that are subjected to constant or frequent vibration. Visually check that piping welds are structurally sound with no

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 accidentally 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.

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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

**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

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.

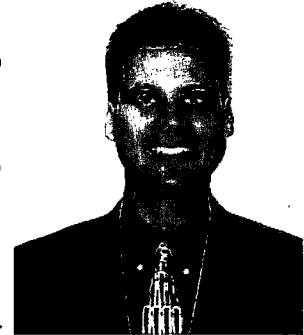


Mark Sitek, Resident Inspector

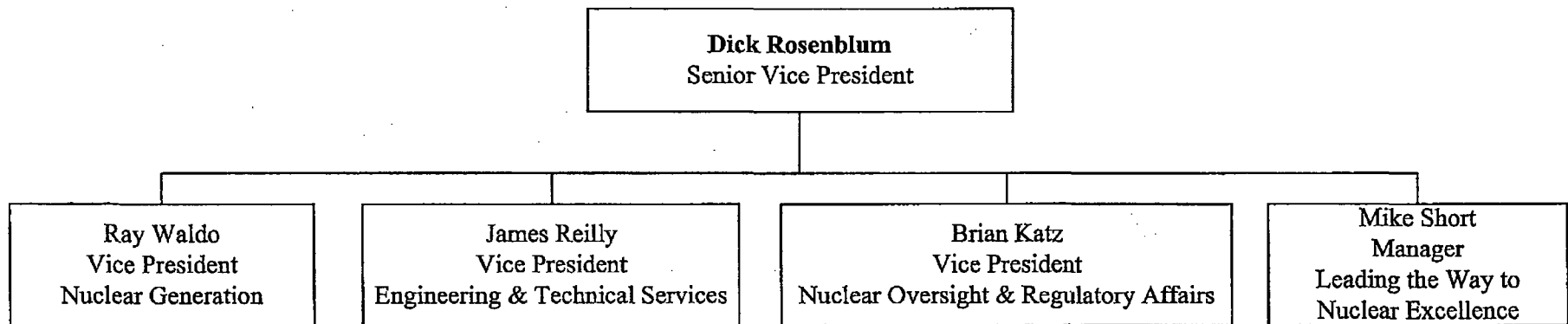
Mark Sitek is the Resident Inspector at San Onofre Nuclear Generating Station. Mr. Sitek joined the agency through the NRC's Graduate Fellowship Program in June 1996. He entered the program following completion of his Bachelor of Science in Nuclear Engineering from Rensselaer Polytechnic Institute in 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.

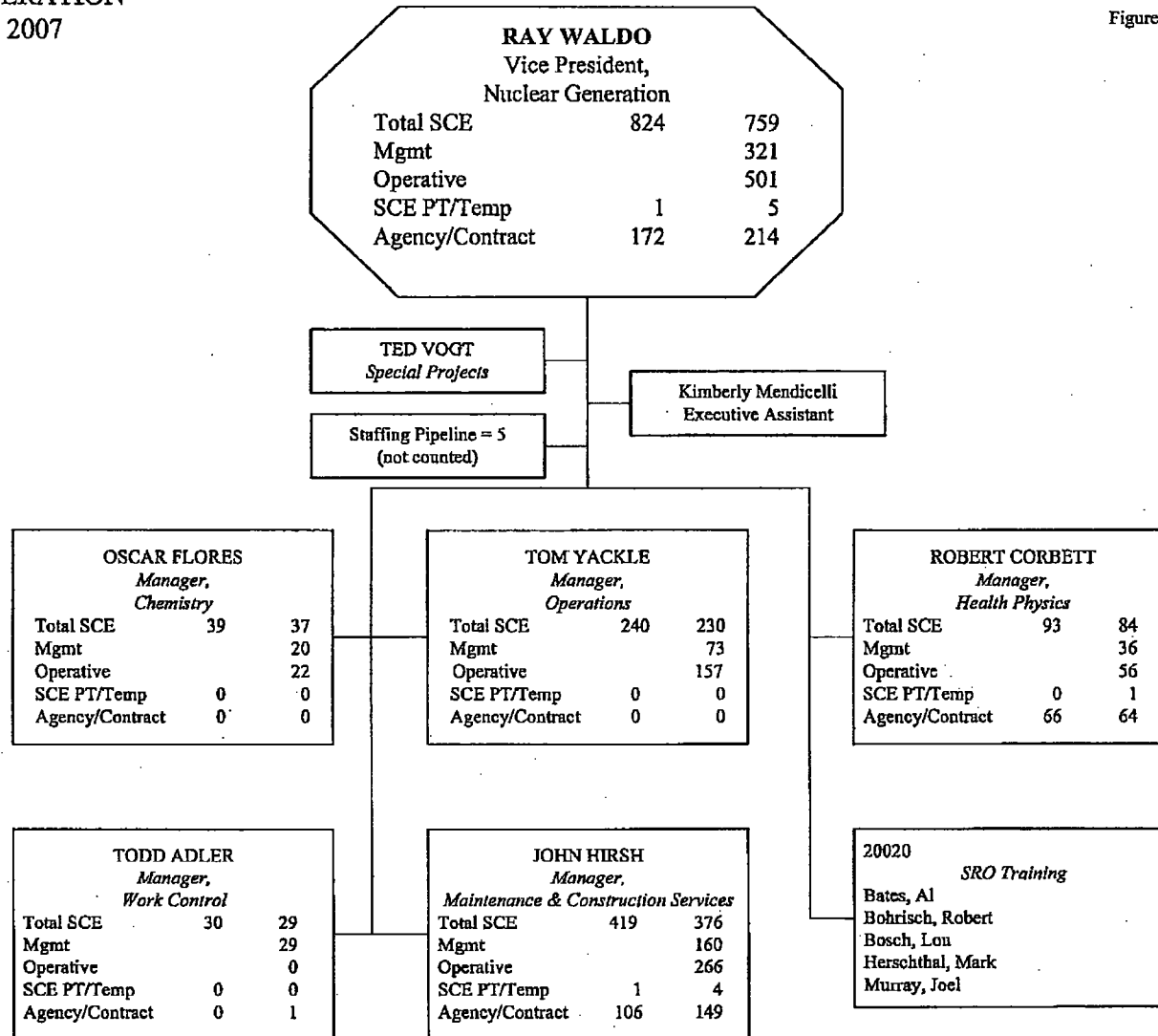


Nuclear Organization



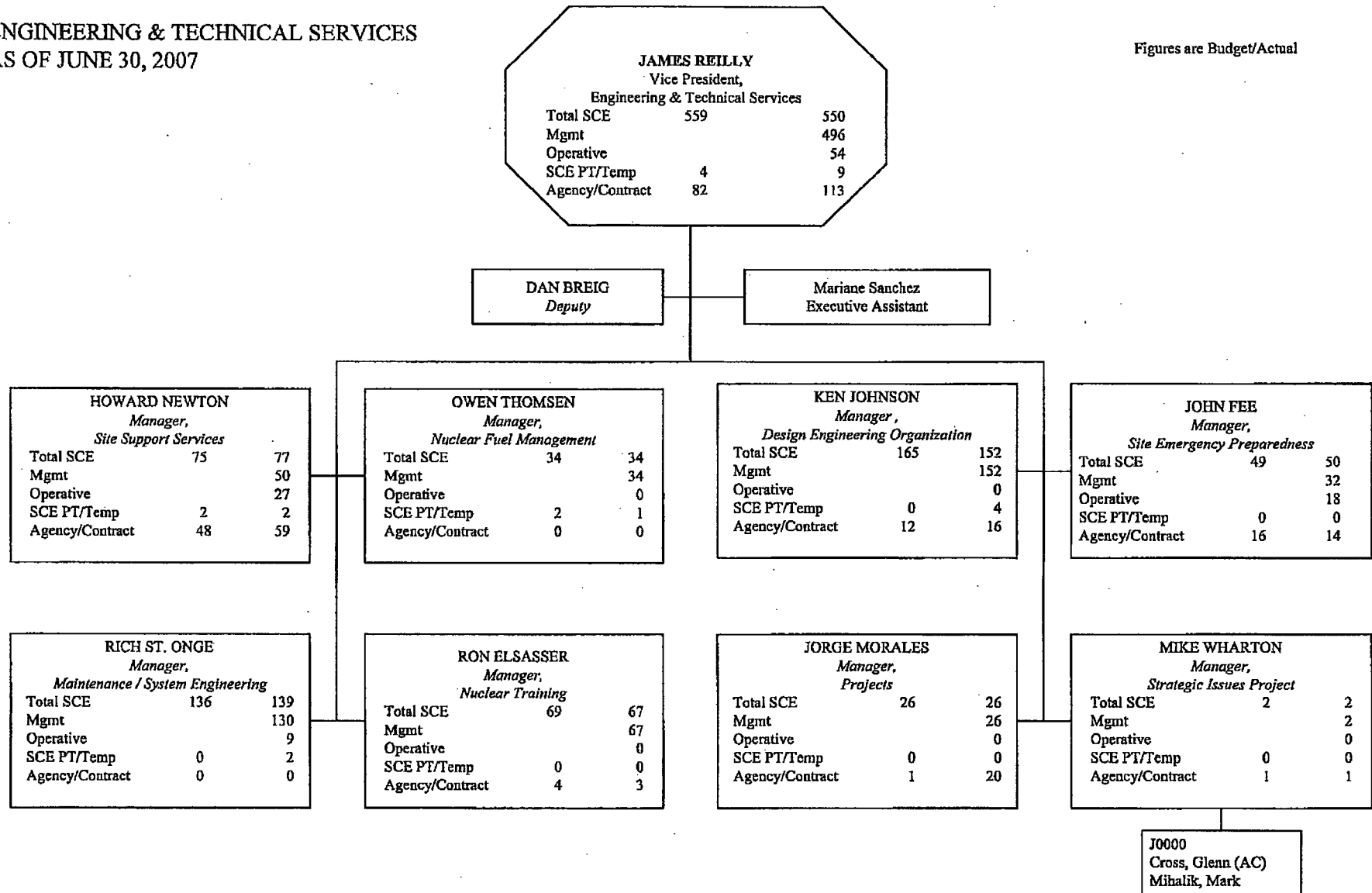
NUCLEAR GENERATION
AS OF JUNE 30, 2007

Figures are Budget / Actual



ENGINEERING & TECHNICAL SERVICES
AS OF JUNE 30, 2007

Figures are Budget/Actual



(*) = Loaned from other depts (not counted)
(I) = Loaned to March to Excellence (counted)

**NUCLEAR OVERSIGHT & REGULATORY AFFAIRS
AS OF JUNE 30, 2007**

Figures are Budget/Actual

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

* = Security not included in totals

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

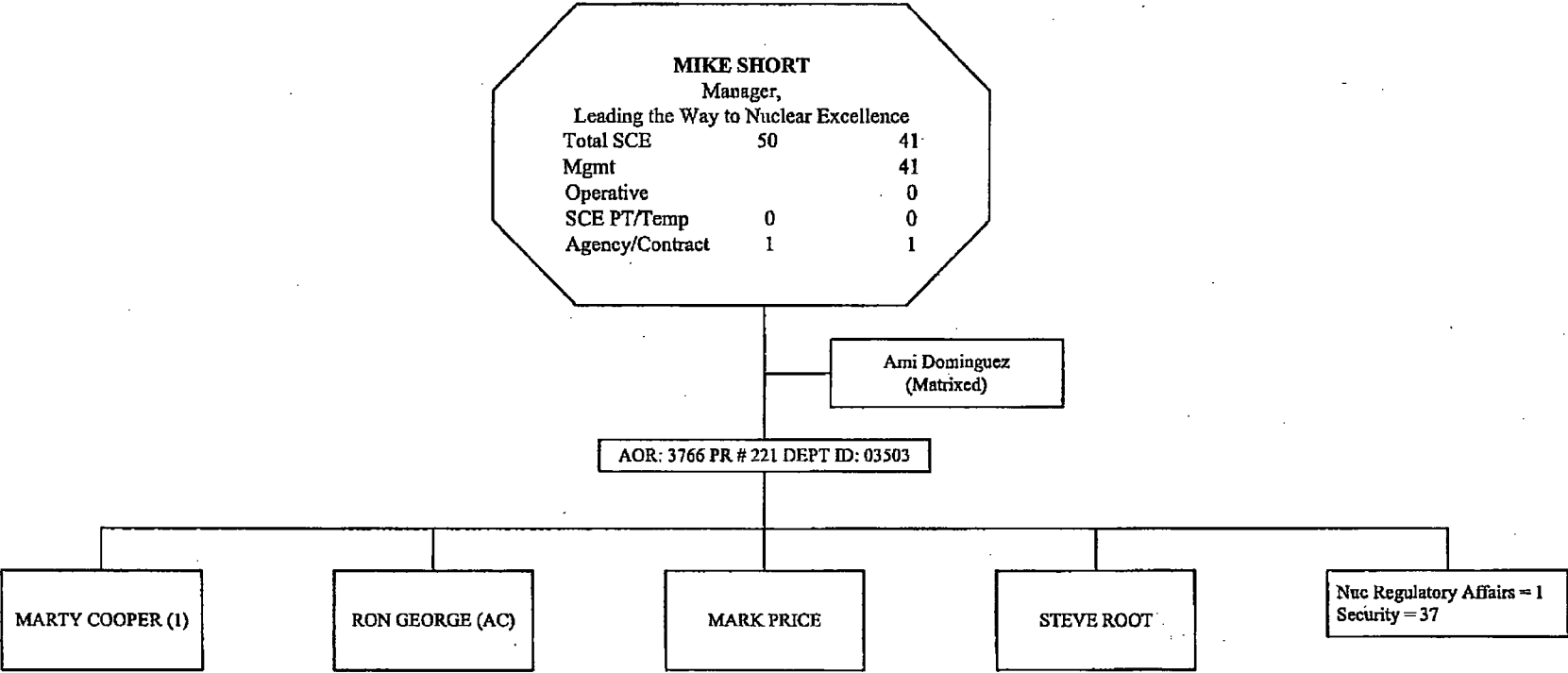
JOHN TODD Manager, Site Security		
Total SCE	438	456
Mgmt		
Operational Support		
SCE PT/Temp	0	0
Agency/Contract	1	0

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	
---	--

LEADING THE WAY TO NUCLEAR EXCELLENCE
AS OF JUNE 30, 2007



(1) = Loaned from OPS (not counted)

Legend
(AC) = Agency / Contract



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.



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.



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 supervisor 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.



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.



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 initiatives 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.



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.



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:
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David J. Bannister
Manager - Fort Calhoun Station
Omaha Public Power District
Fort Calhoun Station FC-1-1 Plant
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 Resident Inspector (**LMW1**)
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 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

R:\ REACTORS\ FCS\2006\FC2006-04RP-JDH.wpd

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	
LJSmith	DAPowers	ZKDunham	
/RA/	/RA/	/RA/	
11/7/06	11/9/06	11/14/06	

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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
Accompanying Personnel: E. Uribe, Reactor Inspector (NSPSP)
Contractor R. Mullikin, Contractor, Engineering Branch 2
L. Eilershaw, Professional Engineer, Consultant
Approved By: Zachary K. Dunham, Chief, Project Branch E
Division of Reactor Projects

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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 Regualification 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

40A1 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 than 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

actuators, 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. Reinhart, 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

<u>Number</u>	<u>Title</u>	<u>Revision</u>
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

<u>Number</u>	<u>Title</u>	<u>Revision</u>
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

<u>Number</u>	<u>Title</u>	<u>Revision</u>
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

<u>Number</u>	<u>Title</u>	<u>Revision</u>
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			

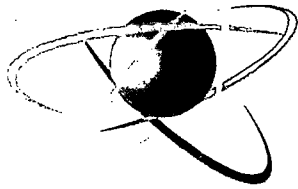
Miscellaneous

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	<i>Code of Federal Regulations</i>
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

**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

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
T. Pat Gwynn, Deputy Regional Administrator
Dwight Chamberlain, Direction, 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. 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

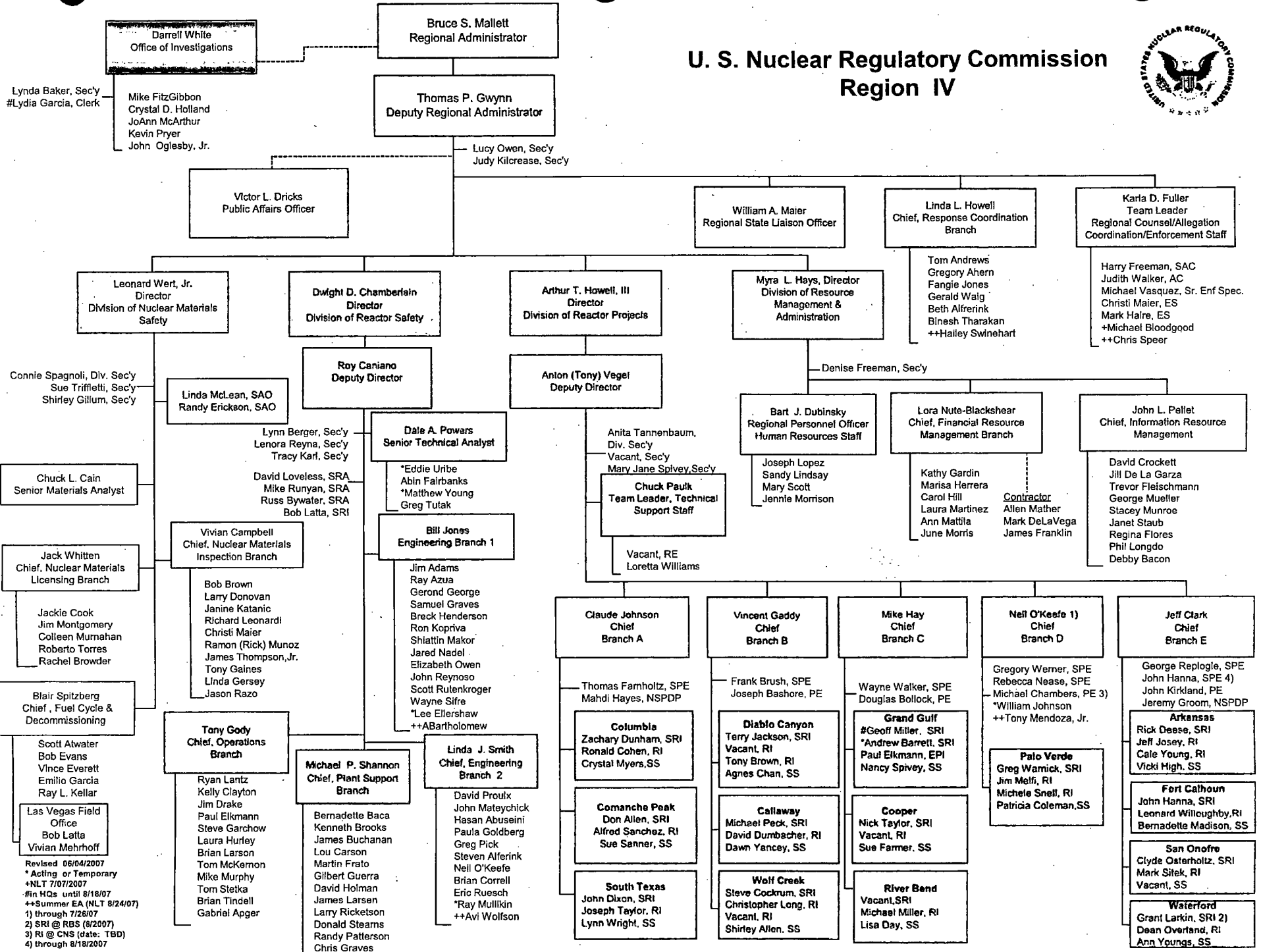
Office of NRR Staff

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



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 7/26/07
 2) SRI @ RBS (8/2007)
 3) RI @ CNS (date: TBD)
 4) through 8/18/2007



UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
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.

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JULY 2005



UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
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



UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
611 Ryan Plaza Drive - Suite 400
Arlington, Texas 76011-4005



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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UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
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.

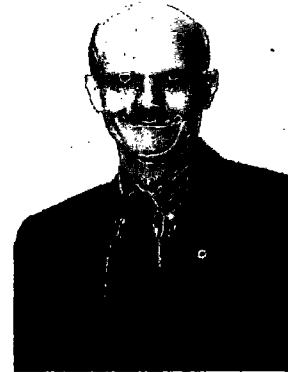
Mr. Chamberlain was assigned to his current position as the Director of the Division of Reactor Safety in November of 2002. Mr. Chamberlain also served as Acting Deputy Regional Administrator in Region IV for approximately four months in FY2003.

January 2004



UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
611 Ryan Plaza Drive - Suite 400
Arlington, Texas 76011-4005

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.



UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
611 Ryan Plaza Drive - Suite 400
Arlington, Texas 76011-4005



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, Ms. 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."



UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
611 Ryan Plaza Drive - Suite 400
Arlington, Texas 76011-4005

Antone (Tony) Vogel
Deputy Director
Division of Reactor Projects



Tony Vogel 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. Vogel 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. Vogel had extensive field experience as an inspector at both boiling water reactor and pressurized water reactor nuclear power generation facilities. Mr. Vogel 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. Vogel 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. Vogel 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. Vogel was an officer in the U. S. Navy Submarine force. Mr. Vogel 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
NUCLEAR REGULATORY COMMISSION
OFFICE OF PUBLIC AFFAIRS, REGION IV
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



Region IV Overview and Challenges

**Bruce S. Mallett, Ph.D., Regional Administrator
T. P. (Pat) Gwynn, Deputy Regional Administrator**

Slide 1



Knowledge Management Overview

**Joseph Lopez, Human Resources Management Specialist
Roy Caniano, Deputy Director, Division of Reactor Safety**



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



Reactor Oversight Process Case Study #1

John David Hanna, Senior Resident Inspector, FCS



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



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



Questions?

12

Slide 2



- STARS
- Resident Inspector Counterpart Meetings
- Inspector Newsletter
- Daily Morning Meeting
- Operating Experience

2



ROP Case Study #2

Wayne C. Walker, Senior Project Engineer




Successful Use of the ROP

➤ Closed CAL and Action Matrix Deviation Memorandum

- Conducted team inspections and held public meetings

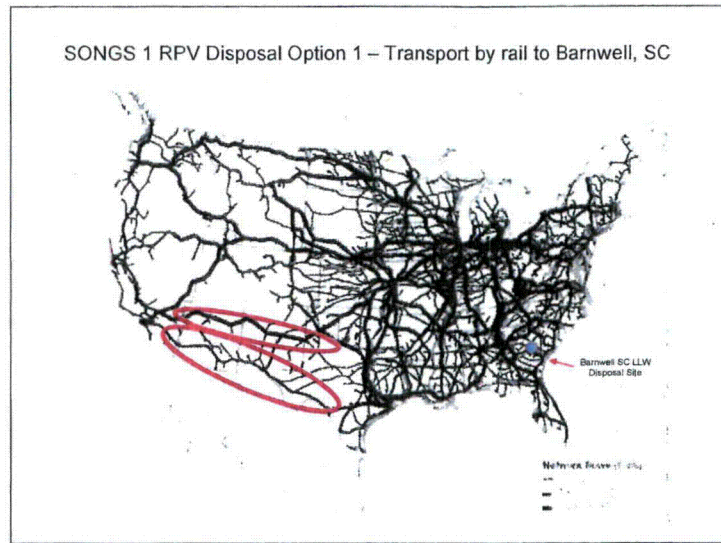
➤ NPPD returned to Licensee Response Column of Action Matrix



Contents

- Historical performance
- Current performance
- Value added through the ROP

2



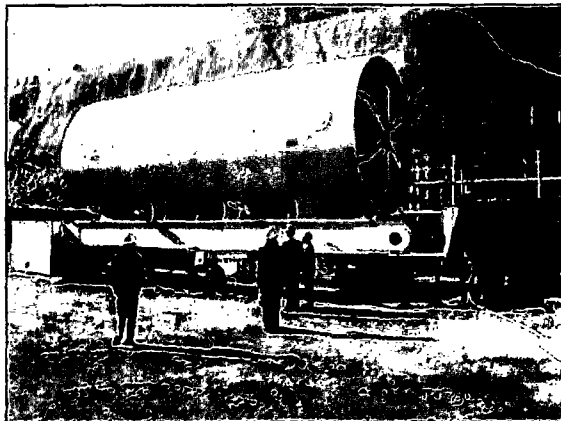
Slide 5

Disposal Option 2 – Transport by (Unsinkable) Sea Barge through Panama Canal to Barnwell, SC



Slide 7

Disposal Option Selected – Leave it onsite until other options develop or until the entire site is decommissioned





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



Challenging RIV Inspection Issues in ISFSI Arena

- Canister Handling Crane Issues
- Use of Lightweight Transfer Cask
- ISFSI Construction with Ongoing Legal Issues



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



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

Slide 13

SONGS ISFSI







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)



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




NRC ROP/Safety Culture Program Assessment

- 95003 Lessons Learned Report
- Cross-Regional Participation MOC/EOC
- NRC Wide Cross-Cutting Issue review – Roy Caniano



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



Findings

Nationwide

- Green – 136 findings and violations
- White – 1 - Vortexing Issue at Clinton and (Region III)

Region IV

- Green – 24 findings and violations

6



Find Latent Design Issues

- Not everything that occurred at TMI was a "risk significant" problem.



Strengths

- Looking deeper into design
- Identifying design problems in place since construction
- Evaluate licensee maintenance of design

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

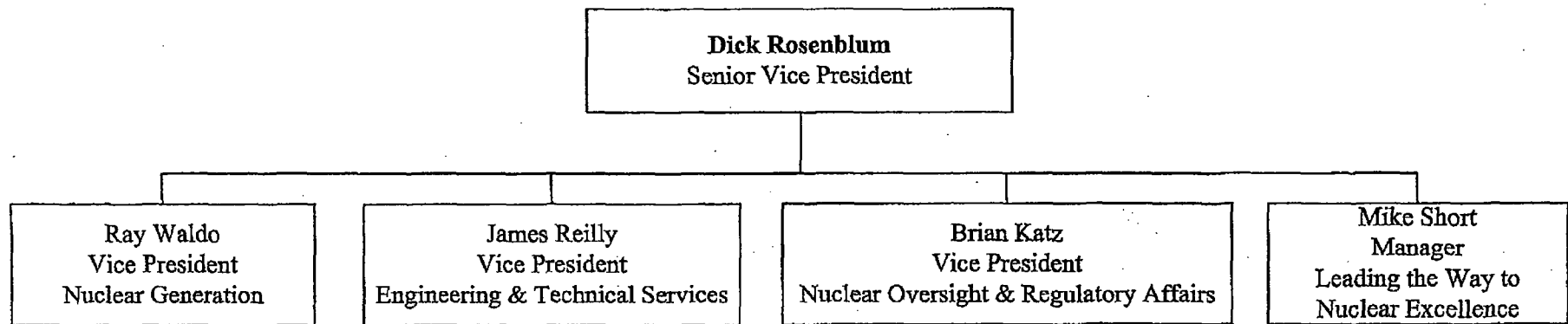
Mark Sitek is the Resident Inspector at San Onofre Nuclear Generating Station. Mr. Sitek joined the agency through the NRC's Graduate Fellowship Program in June 1996. He entered the program following completion of his Bachelor of Science in Nuclear Engineering from Rensselaer Polytechnic Institute in 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.

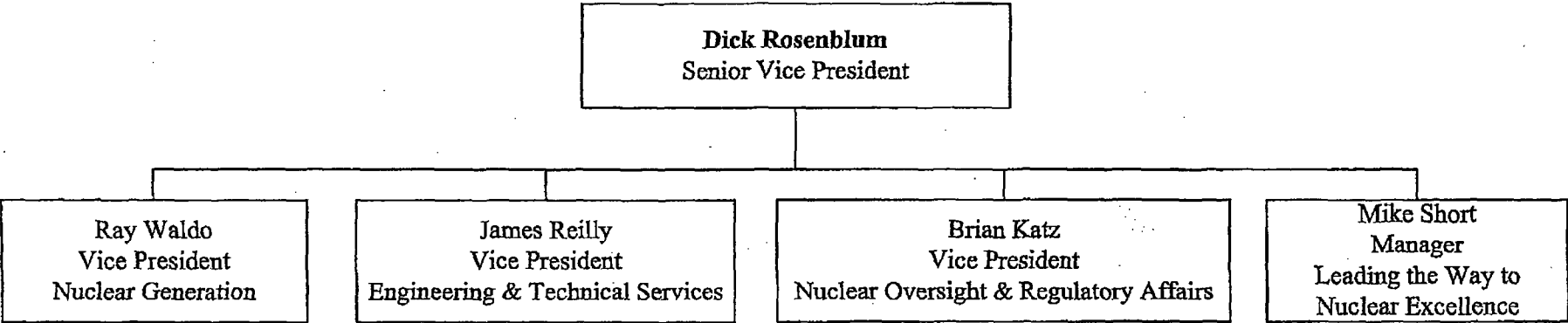
Mr. Sitek became the Resident Inspector at San Onofre in May 2002. Since that time, he has completed rotational assignments as Senior Resident Inspector at Grand Gulf Nuclear Station and as Team Leader, Technical Support Staff in Region IV.



Nuclear Organization

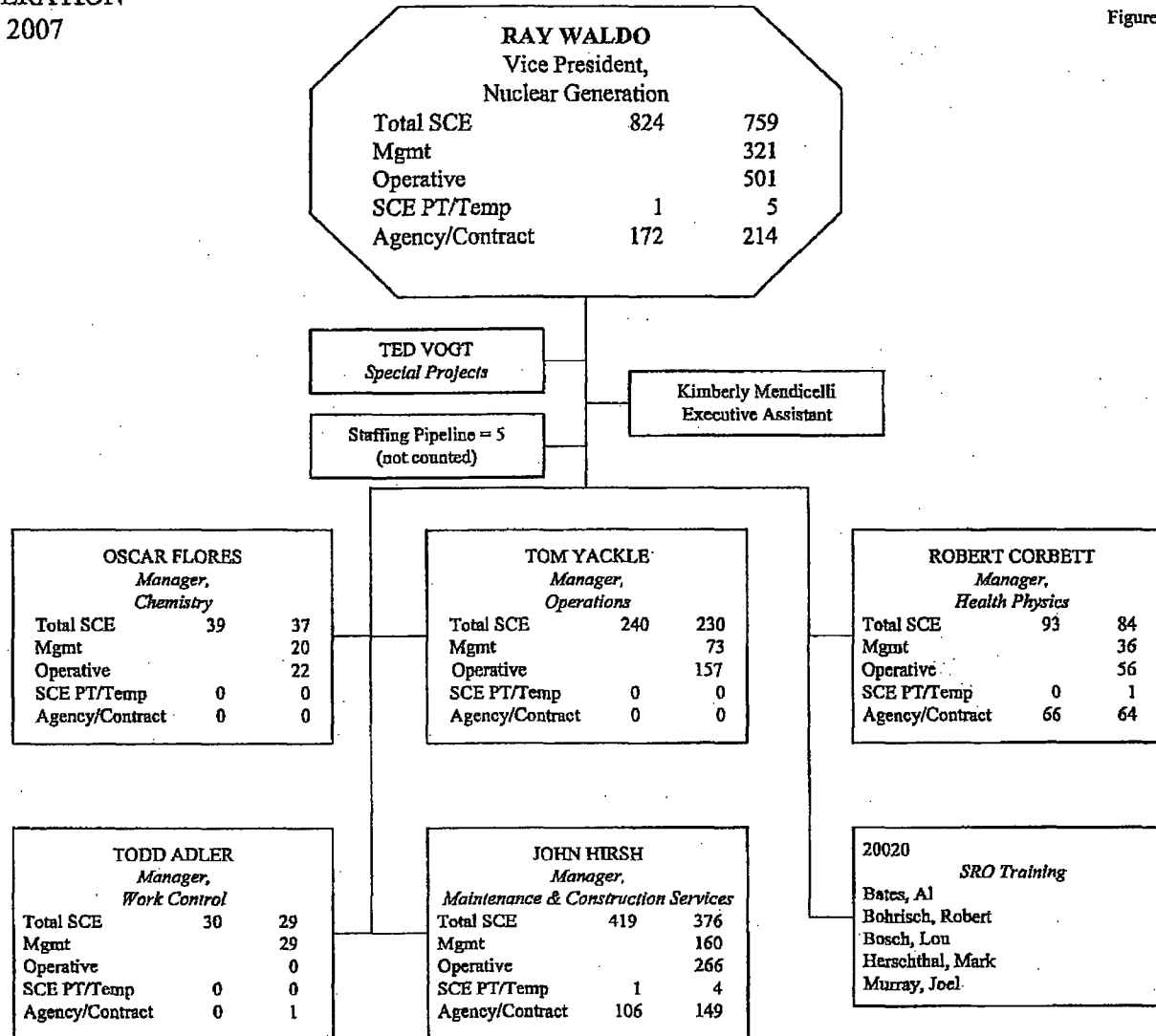


Nuclear Organization



NUCLEAR GENERATION
AS OF JUNE 30, 2007

Figures are Budget / Actual



**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 <i>Deputy</i>	
-----------------------------------	--

Mariane Sanchez <i>Executive Assistant</i>	
--	--

HOWARD NEWTON <i>Manager,</i> <i>Site Support Services</i>			
Total SCE	75		77
Mgmt			50
Operative			27
SCE PT/Temp	2		2
Agency/Contract	48		59

OWEN THOMSEN <i>Manager,</i> <i>Nuclear Fuel Management</i>			
Total SCE	34		34
Mgmt			34
Operative			0
SCE PT/Temp	2		1
Agency/Contract	0		0

KEN JOHNSON <i>Manager,</i> <i>Design Engineering Organization</i>			
Total SCE	165		152
Mgmt			152
Operative			0
SCE PT/Temp	0		4
Agency/Contract	12		16

JOHN FEE <i>Manager,</i> <i>Site Emergency Preparedness</i>			
Total SCE	49		50
Mgmt			32
Operative			18
SCE PT/Temp	0		0
Agency/Contract	16		14

RICH ST. ONGE <i>Manager,</i> <i>Maintenance / System Engineering</i>			
Total SCE	136		139
Mgmt			130
Operative			9
SCE PT/Temp	0		2
Agency/Contract	0		0

RON ELSASSER <i>Manager,</i> <i>Nuclear Training</i>			
Total SCE	69		67
Mgmt			67
Operative			0
SCE PT/Temp	0		0
Agency/Contract	4		3

JORGE MORALES <i>Manager,</i> <i>Projects</i>			
Total SCE	26		26
Mgmt			26
Operative			0
SCE PT/Temp	0		0
Agency/Contract	1		20

MIKE WHARTON <i>Manager,</i> <i>Strategic Issues Project</i>			
Total SCE	2		2
Mgmt			2
Operative			0
SCE PT/Temp	0		0
Agency/Contract	1		1

J0000 Cross, Glenn (AC) Mihalik, Mark	
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(*) = 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

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

* - Security not included in totals

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

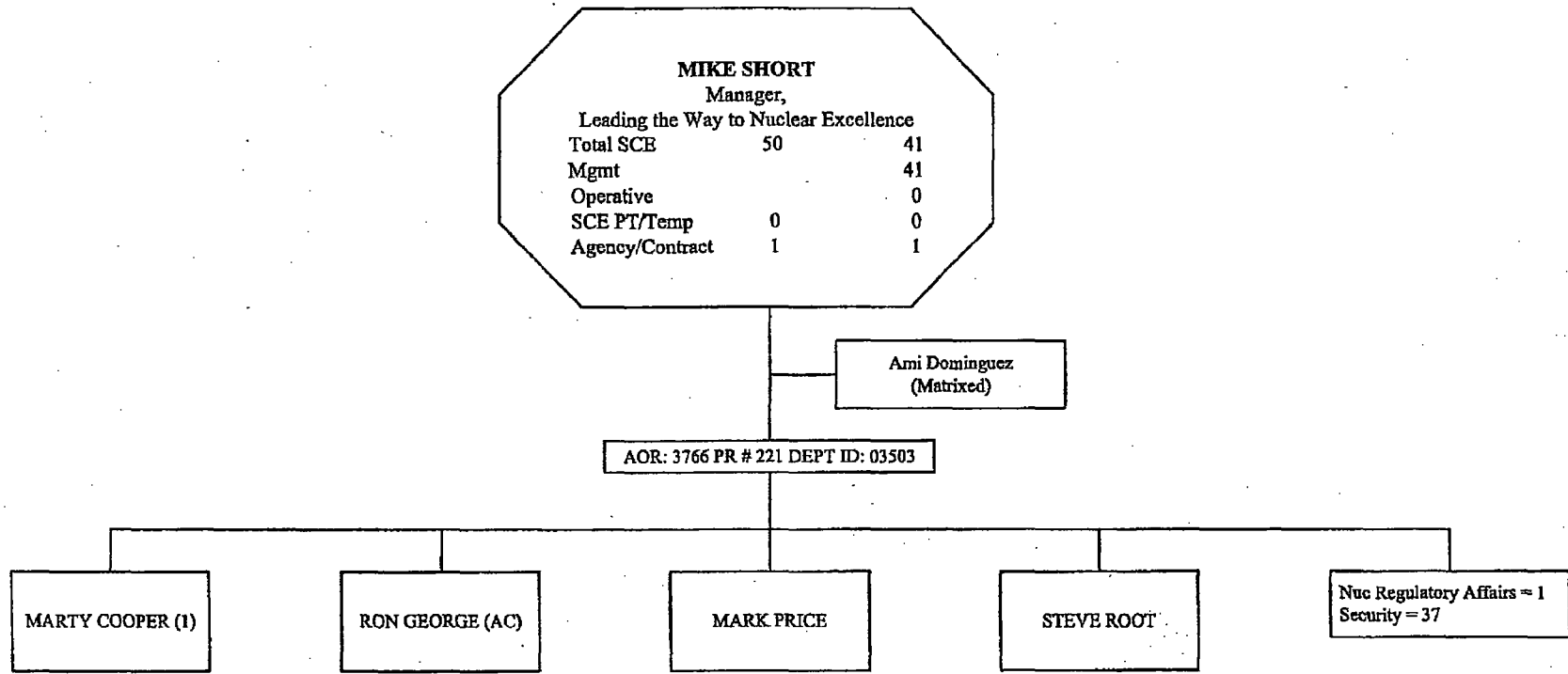
A. E. SCHERER Manager, Nuclear Regulatory Affairs		
Total SCE	23	19
Mgmt		19
Operative		0
SCE PT/Temp	0	0
Agency/Contract	0	1

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

LEADING THE WAY TO NUCLEAR EXCELLENCE
AS OF JUNE 30, 2007

Figures are Budget/Actual



(1) = Loaned from OPS (not counted)

Legend
(AC) = Agency / Contract



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.



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.



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 supervisor 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.



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.



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 initiatives 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.



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.



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