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COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:

Preparation of the 2009 Integrated)
Energy Policy Report)

Options for Maintaining Electric)
System Reliability)

Docket No.
09-IEP-10



ORIGINAL

CALIFORNIA ENERGY COMMISSION

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1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MAY 11, 2009

10:00 A.M.

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SAN RAFAEL, CA 94901

(415) 457-4417

Reported By: Mary Clark CERT*D-214

1 Committee Members Present

2 Suzanne Korosec, Cec
3 Jeffrey Byron, Cec
4 Yakout Mansour, Caiso
5 Steve Stmarie, Cpuc
6 Susan Brown, Cec
7 Jon Bishop, Wrcb
8 Michael Jaske, Cec
9 David Vidaver, Cec
10 Dennis Peters, Caiso
11 Robert Strauss, Cpuc

12 Also Present

13 Laurie Tenhope, Cec
14 John Bohn, Cpuc
15 Kristy Chew, Cec

16 Panel 1: Environmental Agencies

17 Mike Jaske, Cec, Moderator
18 Jon Bishop, Wrcb
19 Mohsen Nazemi, Sciqmd
20 Mike Tollstrup, Arb
21 Al Wanger, Ccc

22 Panel 2: Electric Generators

23 David Vidaver, Cec, Moderator
24 Eric Leuze, Rri Energy
25 Sean Beatty, Mirant

1 Panel 2 Continued,

2 Randy Hickok, Dynegy

3 Eric Pendergraft, Aes

4 Jesus Arredondo, Nrg

5 Panel 3: Utilities

6 Mike Jaske, Cec, Moderator

7 Mark Minick, Sce

8 Gordon Savage, Sce

9 Mark Krausse, Pg&E

10 Curt Hatton, Pg&E

11 Rob Anderson, Sdg&E

12 Eric Tharp, Ladwp

13 Panel 4: Environmental Community

14 Mike Jaske, Cec, Moderator

15 Deborah Sivas, Stanford Environmental Law Clinic

16 Angela Haren, California Coastline Alliance

17 Joe Geever, Surfrider Foundation

18 Bill Powers, California Coastline Alliance

19 Leila Monroe, National Resources Defense Council

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P R O C E E D I N G S

1
2 MS. KOROSSEC: Good morning everyone. I'm
3 Suzanne Korosec. I lead the Energy Commission's
4 Integrated Energy Policy Report Unit. Welcome to today's
5 workshop on options for maintaining electric system
6 reliability when eliminating once-through cooling power
7 plants. It's being conducted by the Energy Commission's
8 Integrated Energy Policy Report or IEPR Committee in
9 conjunction with the California Public Utilities
10 Commission and the California Independent System Operator.

11 Unfortunately, Commission Bohn was unable to
12 join us today. I understand he's not well, but in his
13 place he's being ably represented by his advisor, Steven
14 St. Marie. Welcome, Steven. And also we'd like to
15 welcome Mr. Mansour from CA ISO. We really appreciate
16 having you here today.

17 Just a few housekeeping items before we get
18 started. The restrooms are out the double doors and to
19 your left. There's a snack room on the second floor at
20 the top of the stairs under the white awning. And if
21 there's any sort of emergency and we need to evacuate the
22 building, please follow the staff out the door to
23 visitor's park, which is diagonal building and wait there
24 for the all clear signal.

25 Today's workshop is being broadcast through our

1 WebEx teleconferencing system, and for parties who are
2 using that system who would like to ask a question or
3 speak through the comment period, you can use the raised
4 hand feature or you can send a chat email directly to the
5 WebEx coordinator.

6 Just a little brief context before I go over
7 today's agenda. The Energy Commission is required by
8 statute to develop and IEPR every two years that provides
9 an overview of major energy transit issues that are facing
10 the state along with policy recommendations to help the
11 state meet its energy related goals. The issue of once-
12 through cooling in power plants had come up at every IEPR
13 since the first one was published in 2003.

14 The 2003 IEPR adopted a policy on water use in
15 power plants requiring new plants to use degraded or
16 recycled water or an air-cooled system and to use zero
17 liquid discharge technologies unless doing so would be
18 shown to have significant adverse environmental impact or
19 to be economically or otherwise infeasible. This was
20 intended to reduce the amount of fresh water and its use
21 in power plant cooling systems and the impact of these
22 systems on the environment.

23 The 2005 IEPR raised the issue again and noted
24 the need for additional study of the ecological effects of
25 once-through cooling and directed the Energy Commission to

1 work with other state agencies and address these issues in
2 the broader context of protecting the state's coastal
3 marine ecosystems.

4 The 2007 IEPR discussed legal challenges
5 associated with the use of once-through cooling in
6 existing power plants, and noted that licensed
7 applications for new power plants proposes the use of
8 once-through cooling could be substantially delayed or
9 denied because of those challenges. The 2007 IEPR also
10 noted that there are potential liabilities impacts
11 associated with these legal challenges since two-thirds of
12 California's coastal power plants are located in Southern
13 California, which already faces reliability challenges due
14 to the number of aging plants plus the shortage of
15 emission credits that are available for new plants in that
16 region.

17 For the 2009 IEPR, we're once again looking at
18 this issue and this time really focusing on the impact of
19 the reliability -- excuse me, on reliability of the
20 proposed regulations to restrict once-through cooling.
21 The goal of our efforts is to implement a once-through
22 cooling mitigation policy for existing generators that's
23 integrated with planning and development of replacement
24 infrastructure that will be needed to support reliability.
25 If owners of plants that use once-through cooling decide

1 to retire their plants rather than meet the new
2 requirements, you could have a severe effect on
3 reliability particularly in Southern California given the
4 recent court decisions about the priority reserve credits
5 and the uncertainty about whether new plants could
6 be permitted in the South Coast Air Management District's
7 airshed.

8 So the purpose of today's workshop is really to
9 get feedback from all of you on how the state's energy
10 agencies may need to modify our existing planning
11 procurement and permitting processes to allow the
12 development of new infrastructure like generation or
13 transmission or other system elements that can reduce the
14 reliability impacts of the proposed once-through cooling
15 mitigation policy.

16 So I'm just going to briefly go over today's
17 agenda. First, we'll have opening comments from the Dais
18 followed by a presentation by Jon Bishop from the State
19 Water Resources Control Board on the environmental impacts
20 of once-through cooling and mitigation proposals.

21 Next, we'll have an overview of reliability
22 issues from the Energy Commission, CA ISO, and the CPUC
23 staff, followed by a one-hour panel to hear from the
24 state's environmental agencies. We hope to take our lunch
25 break at 12:30 and resume at 1:30, followed by three

1 additional one-hour panel discussions, one with the
2 electricity generators, one with utilities, and one with
3 the environmental community.

4 And once we've completed the final panel
5 discussion, we'll take time for public comments. First,
6 from those in the room and then from parties listening on
7 the phone, and then Dr. Jaske will do a brief wrap-up of
8 the day.

9 We do ask that parties wishing to speak during
10 the public comment period today fill out a blue card.
11 These are available on the table out in the foyer. You
12 can give those to me throughout the day, and I'll pass
13 them on to the Commissioners. Depending on the number of
14 parties wanting to speak, we may need to limit the time
15 for each party. We'll see once we start seeing the cards
16 coming in, but please know that we do value your input and
17 we want to try to fit everyone in who wants to talk today.

18 So unless there are any other questions, I would
19 like to pass this on to the Dais for public comments.

20 COMMISSIONER BYRON: Thank you, Ms. Korosec, and
21 thank you all for being here particularly my colleagues
22 from the ISO and the Public Utilities Commission. Thank
23 you for being here.

24 I think those of you that are in the know on
25 this particular issue understand the significance of the

1 implications of the once-through cooling issue. And I can
2 tell by your attendance here today that we're going to
3 have a very good discussion around this topic. There's a
4 lot of effort that's been underway at the energy agencies
5 and the Water Resource Control Board on this particular
6 issue. We have met numerous times on this issue as well
7 here amongst the PUC, Energy Commission, and the
8 Independent System Operator.

9 As Ms. Korosec said, this workshop we're really
10 interested in the input from the various stakeholders
11 about the reliability issue associated with implementation
12 of the once-through cooling mitigation policies. And
13 we're not going to debate the virtues or the implications
14 of the actual once-through cooling rule that's being
15 promulgated, although I did find myself instead of
16 counting sheep last night before I went to sleep trying to
17 calculate the cubic meters of 15 billion gallons of water
18 a day that has passed through all of these power plants.

19 I think I'll keep my remarks short. I'm very
20 interested in hearing from all of you, and we'll make sure
21 there is ample time for public comment. I'd like to ask
22 if any other of my folks at the Dais would like to say
23 anything. Mr. Mansour?

24 MR. MANSOUR: Thank you, Commissioner. Thank
25 you, Commissioner. As always, I want to thank you and the

1 Energy Commission for staying on top of this issue.
2 You've always demonstrated really keen interest in what
3 matters to the state and particularly this industry.

4 As most of you and all of you know, the ISO's
5 mission states a commitment to reliability, efficient
6 market, which indicates reasonable cost, and alignment of
7 federal and the state policies. In many cases, they are
8 perfectly aligned. In some cases to meet all three or
9 called to strike the right balance, it's an order.
10 Unfortunately or fortunately, depending on how we look at,
11 reliability is not a compromise. Today's discussion is
12 all about this, striking the right balance.

13 And while we commit to facilitating the state
14 policies, it is important to recognize the challenge of
15 operating a grid with a massive amount of intermittent
16 resources while restricting the operation of the existing
17 facilities so as needed to backup is a major challenge.
18 No one knows more than California that when lights go off
19 or rates have gone higher, nothing else matters and
20 everything else changes. So for us to actually make sure
21 that all (inaudible) stay intact and achieve their
22 purpose, we have to make sure that the lights do not go
23 off and prices stay reasonable.

24 Our role is to find that balance and provide the
25 supply, reasonable cost, and environmentally friendly

1 future. I look forward to the rest of the day.

2 COMMISSIONER BYRON: Mr. St. Marie?

3 MR. ST. MARIE: Thank you, Commissioner Byron,
4 for having me. I'm Steve St. Marie. I work for
5 Commissioner Bohn. Commissioner Bohn sends his regrets.
6 He is quite ill and we're all better off for not having
7 him around here, as well as he's better off being at home.
8 I'll do my very best. Thank you.

9 COMMISSIONER BYRON: Thank you. Ms. Brown?

10 MS. BROWN: I'm Susan Brown. I'm representing
11 Commissioner Jim Boyd, who unfortunately couldn't be here
12 today, and I can assure you that this is an issue of
13 utmost importance in his mind. Commissioner Boyd was an
14 air regulator for many years. He's very sensitive to the
15 confluence of some of the issues that we've heard mention
16 already today.

17 We have -- We're assigned to something, I think,
18 ten or eleven power plant siting cases, and each of these
19 brings forward the need I think to integrates what often
20 appears to be conflicting state policy goals and single
21 systems approach, so I'm hoping to get educated further
22 today. And Commission Boyd would have like to have been
23 here if he could, so thank you.

24 COMMISSIONER BYRON: Thank you, Ms. Brown. And
25 also with the Dais with us today is my Senior Advisor,

1 Ms. Laurie Tenhope. Laurie, did you have anything you
2 wanted to say?

3 MS. TENHOPE: No, thanks.

4 COMMISSIONER BYRON: All right. Thank you all
5 so much for your comments. I think we're going to go
6 ahead and get started with the agenda if I may introduce
7 our first speaker, Mr. Jon Bishop, Statewide Resource
8 Control Board.

9 Mr. Bishop, thank you for being here this
10 morning. I'm sure you're going to put this all in
11 perspective for us.

12 MR. BISHOP: Well, I will try. Thank you very
13 much for having me here today.

14 What I plan to do today is give you all a
15 background on where we are and why we're looking at once-
16 through cooling policy for the state, and then touch on
17 the approach that we're proposing at this point.

18 Here we go. All right, now I've got this
19 figured out. We currently have approximately 19 plants
20 that use once-through cooling. That's something like 15
21 billion gallons per day sent through these cooling
22 systems. These plants are located all over the state from
23 Humboldt County down to San Diego. It just depicts and
24 some of the grid infrastructure on there. I'm not going
25 to go through each plant at this time, but this is just to

1 give you an idea of where they are.

2 The reason that the State Water Resources
3 Control Board has been looking at the statewide policies
4 for mitigating the impacts of once-through cooling is that
5 there are some serious impacts. We have thermal discharge
6 impacts, which include not only the thermal but also the
7 waste associated with the chemicals used for treatment in
8 the plant and sometimes human waste that's comingled with
9 discharge. We have impingement, which is the act of
10 getting large organisms impinged or trapped on the
11 screens, the intake screens for the plant, and then
12 entrainment where the small larvae are actually brought
13 through the plants itself, and then are killed with the
14 heat systems.

15 Just to give you some idea over the last few
16 years, we have been working with many of the energy
17 companies to come up with estimates on these impacts.
18 Something about 97,000 pounds of fish and
19 macroinvertebrates are impinged each year on these plants.
20 We have a smaller but still significant number of large
21 organisms, marine mammals, and sea turtles, more around 50
22 to 60 of those, and then a very large amount of fish
23 larvae and eggs that are entrained each year. We also
24 have the impact associated with the thermal discharges.

25 I just want to take a minute and think about

1 this. We have a -- If we have fish kill associated with
2 the discharge from one of our plants, that usually makes
3 the front page of the paper. We don't -- We have zero
4 tolerance for fish kills in most of our discharges, but we
5 expect it from these once-through cooling plants. It's
6 part of the operation. It's something that we need to be
7 addressing and looking to reduce.

8 Our goal is to develop a statewide policy to
9 minimize these impacts. At the time, the last thing that
10 we want to do is be responsible for an impact on the grid.
11 I really do not want to add to my résumé that I was in
12 charge of policy that shutdown the grid and turned out the
13 lights in California. So we have been working --

14 COMMISSIONER BYRON: None of us want that one.

15 MR. BISHOP: -- to try to mitigate both the
16 impacts of once-through cooling and mitigate the impacts
17 of moving away from once-through cooling.

18 I will go into a little bit more detail about
19 how we've been doing that in a minute, but we've been
20 working with representatives of your agencies and others
21 to bring in a different perspective than just the State
22 Water Board's perspective.

23 Why are we here? Well, the Clean Water Act,
24 Section 316(b), requires that we look at the design,
25 construction, and best available technology for minimizing

1 the adverse impacts. Also, the California Water Code or
2 the Cologne Act requires us to do the same thing. It's
3 slightly different language but essentially under both of
4 those requirements, we are charged with the task of
5 minimizing the impacts from once-through cooling on the
6 marine environment.

7 The way this works is that under both -- under
8 316(b) under the State Water Board, we are required to
9 permit once-through cooling power plants under an NPDES,
10 which is a National Pollutant Discharge Elimination System
11 Permit. That's the Clean Water Act permitting authority.

12 There are not any existing federal regulations
13 that are in place or state regulations for how that would
14 be accomplished for existing facilities. So for the last
15 30 years, the Regional Boards have been using best
16 available -- best professional judgment to look at what is
17 the best available technology for minimizing those
18 impacts.

19 We are under a requirement to renew these
20 permits on a five-year scheduling. The Clean Water Act
21 NPDES permits are good for five years, and if those go
22 beyond that five-year period, they are extended
23 administratively, which means that the previous permit
24 stays in place until a new permit is adopted. Many of
25 these permits are -- their permits are expired.

1 The State Regional Boards have been waiting on
2 how to best address that problem, and I'll be blunt. The
3 reason is that there is a very unsure regulatory landscape
4 out there, and they're concerned and we're concerned that,
5 if we go on a plant-by-plant basis around the state, we
6 would end up with a plant-by-plant approach to how to deal
7 with once-through cooling, which might lead from total
8 elimination in one region to total acceptance in another.

9 No matter what a Regional Board does, it's
10 likely that they will basically build challenges on that.
11 The idea of having 19 separate legal challenges with
12 different decisions around the state is not appealing to
13 us as agency, and so I've been tasked with trying to
14 develop a statewide approach that would at least draw the
15 buyers in one place.

16 To give you kind of an idea of where we are, the
17 EPA has been trying for 30 years to put into place rules
18 on once-through cooling power plants. They were able to
19 adopt in 2001 Phase 1, what they called the Phase I Rule,
20 which is for new plants. They also adopted in 2004 Phase
21 II Rules for existing power plants. The Phase II Rule led
22 to court action and appeals.

23 Eventually, it was taken up by the US Supreme
24 Court to address some of those issues. And so back just
25 this a year, a month ago or so, the US Supreme Court put

1 out their decision on the Phase II Rule, and essentially
2 kicked it back saying that EPA did have the authority to
3 use cost in analyzing best available technology but didn't
4 require it. Okay. That's not a very definitive situation
5 for us, I'll have to admit, but that's where we are.

6 So what has the State Board been doing in this?
7 Well, in the last few years, the State Board has been
8 developing statewide policy to look at how to address the
9 impacts from once-through cooling.

10 They had their first in September of 2005, their
11 first scoping meeting on this almost four years ago. They
12 released an early document in 2006, and then the
13 RiverKeeper II Court of Appeals decision came out, and we
14 stepped back and said we need to look at this a little bit
15 differently. We revised the scoping document and in March
16 of 2008, and we came out with a revised scoping document.

17 That scoping document essentially laid out a
18 two-track approach to addressing the impacts of once-
19 through cooling. It said on track one we would be looking
20 at wet recycled cooling or its equivalent or dry cooling
21 as one alternative. And then track two was, if that
22 wasn't feasible either technically or economically, then
23 we would go to track two, which was you had to mitigate
24 those impacts through either new management practices, new
25 intake structures, and new approaches to reach 90 percent

1 of what you would expect to see if you had switched to
2 Phase II -- to recycled cooling.

3 As you might imagine, we received quite a bit of
4 concern on that proposal. And we had laid out in there a
5 time schedule that looked at 2015 for low capacity, less
6 than 20 percent capacity plants, 2018 for high capacity
7 plants, and 2021 for the nuclear plants to come into
8 compliance.

9 After that was out for comment, we received
10 concern from your agencies, from CA ISO, from many of the
11 generators that this would cause problems with grid
12 reliability. We got together. We said, well, that's not
13 really our area of expertise, so how are we going to
14 address that?

15 And the approach that was decided is that we
16 would step back and put together a working group. The
17 working group was made up of members of my staff, myself,
18 the Energy Commission, the Public Utilities Commission,
19 the Independent System Operator, and the Coastal
20 Commission, State Lands, and Air Resources Board. And the
21 charge of this group was to look at how do we implement
22 this approach of the two tracks of meeting the impacts
23 associated with once-through cooling without -- with
24 having a minimal disruption to the grid.

25 I know that you're going to have more on this

1 from Mike Jaske, but I'd like to say that this has been a
2 fabulous opportunity to work with the difference state
3 agencies and sit down and really talk about where our
4 concerns are, where our authorities are, and how we can
5 jointly come together with an approach.

6 Right now, we are putting together the final --
7 Let me get to the next steps. We're putting together the
8 final approach to our proposed rule making. We expect to
9 have that it says up here at the end of summer. I didn't
10 catch that when I was reading it. We expect to have that
11 by the end of June, early July timeframe, and we would
12 have it out public comment at that time with a workshop
13 sometime in August, and hopefully a hearing for adoption
14 in the fall or near the end of the year.

15 We have received from the combination of the
16 Energy Commission, the California Public Utilities
17 Commission, the CA ISO a proposal on how to implement
18 that. We are integrating that into our policy as we
19 speak. I'm very hopeful that this new approach will allow
20 us to meet our needs, which is to address the
21 environmental impacts associated with once-through cooling
22 and also meet our energy needs in the state.

23 And I'm going to be here for most of the day,
24 and I'm happy to try and answer any questions that folks
25 have. But I'd like to say as I end that, you know, most

1 of the time we hear from stakeholders out there is that
2 state agencies need to learn how to talk to each other and
3 get out of their solace and work together.

4 And I know we started out with the approach
5 that, you know, hey, the water is what we worry about and
6 that's what we'll deal with. You guys deal with the
7 energy side of the house. But this working group has
8 actually come together and looked at things from multiple
9 perspectives, and I think that's what good government is
10 about and we should be encouraging it. Thank you very
11 much.

12 COMMISSIONER BYRON: Mr. Bishop, thank you. I
13 know that you're going to be here. We've got a couple of
14 panels that will have an opportunity to ask you a bunch of
15 questions. I just want to check if there are any
16 clarifying questions that you needed as a result. I got
17 one for you if I may.

18 MR. BISHOP: Sure.

19 COMMISSIONER BYRON: You had indicated that the
20 Regional Boards are obviously very keen on getting some
21 direction here. Are they going to be bound by the
22 decision of the State Board?

23 MR. BISHOP: Yes. The easy answer is yes. The
24 way that the State and Regional Boards work is that the
25 Regional Boards are what we call semiautonomous. They

1 have their own board that's appointed by the Governor.
2 They make the initial rulings on permits and enforcement
3 actions and planning documents.

4 They are -- When they make those permit
5 decisions, they have to look to a number of documents, and
6 one of them is any statewide policy that has been adopted.
7 If they miss it either by design or mistake, the State
8 Board then has the opportunity either through a petition
9 or through its own motion review to correct that issue.
10 So when the State Board adopts a policy, then the Regions
11 are required to implement it.

12 COMMISSIONER BYRON: Thank you. And you've
13 given some indication as to the level of effort that's
14 gone on since June of last year amongst the agencies and
15 your board. And I think we'll be demonstrating that more
16 in some of these panels, I think the next panel in
17 particular, and that's, of course, one of the key purposes
18 of this workshop is get that out there for public comment.

19 Mr. Bishop, thank you for being there and for
20 being here today. Let's go ahead and keep moving because
21 I want to make sure we get through these two panels but
22 still have a lunch hour.

23 MR. BISHOP: Okay.

24 COMMISSIONER BYRON: Thank you.

25 MR. BISHOP: Thank you.

1 COMMISSIONER BYRON: Oh, and thank you for your
2 animation. I don't think we've ever had starfish, and
3 trout and goldfish animated on our screens before.

4 MS. KOROSK: All right. Now we'll hear from
5 Dr. Jaske, from the CEC staff.

6 DR. JASKE: Good morning. I'm Mike Jaske from
7 the Energy Commission staff and currently in the
8 Electricity Supply Analysis Division.

9 And oral presentations that you'll get in this
10 session are from persons who have been active in the
11 interagency working group that Mr. Bishop has talked about
12 and in numerous other discussions among the three energy
13 agencies.

14 So I think this slide duplicates what has been
15 said before, and let me just emphasize that we're not here
16 today to debate whether or not the Water Board should
17 implement any particular OTC policy. We're here to figure
18 out, given the OTC policy, what consequences would that
19 have for reliability and how we dovetail those two
20 concerns in such a way that there aren't reliability
21 issues.

22 So as Mr. Bishop said, there were numerous
23 comments received to their scoping document at comment
24 point when those were due in May '08. The Water Board in
25 the scoping document had actually suggested that there

1 will be a statewide taskforce formed, and as it was
2 described there, it was composed of largely the same body
3 of entities that he just ran through earlier, but it
4 wouldn't come into being until after the policy was
5 enacted. And it would serve essentially as a review on
6 the compliance plans that the scoping document envisioned
7 at that point.

8 There were a number of entities that submitted
9 comments that essentially said when you draw upon the
10 expertise of these other agencies while you're developing
11 the final version of the rule, and so Water Board staff
12 formed this multiagency-working group, as Mr. Bishop said,
13 and in particular the Energy Commission, PUC and ISO have
14 been very active since then.

15 So again, I guess I'm repeating part of what
16 Mr. Bishop said. Their preliminary policy of March '08
17 established what cooling tower as sort of the benchmark.
18 Energy Commission staff and I believe our colleagues at
19 the other energy agencies believe that the installation of
20 wet cooling towers is most likely not going to be cost
21 effective for these older plants. Most of these plants
22 that we're talking about, you know, were constructed as
23 far back as the '50s in some instances, and all up and
24 through the '70s, and there are a couple, of course, that
25 are newer than that represent particular challenges.

1 So our current belief is that most of these
2 plants are going to either retire outright or wish to
3 repower rather than refit cooling technologies into the
4 existing power generation equipment. That presumption, of
5 course, is part of what this workshop is all about to see,
6 in particular from the generator community, whether that
7 presumption is accurate or not, and I'm looking forward to
8 that session later today.

9 So in the context of the belief that retirement
10 or repowering is likely to be the consequence, then we
11 need to think about reliability in terms of assuring that
12 replacement infrastructure is, in fact, developed and
13 operational in such a way that it dovetails with the point
14 at which one of these OTC plants does, in fact, retire.

15 And what is the word; I use the word sufficient
16 OTC capacity remains online. What does sufficient mean?
17 It means at least two things, that we have enough total
18 resources to meet the system requirements, but that we
19 also have resources in particular local areas so that
20 local capacity requirements are satisfied.

21 As it turns out, it is actually a very key
22 dimension of this whole puzzle. Most of these plants are,
23 in fact, located in local capacity areas, and we have to
24 look at a bit of a tight scheduling process to ensure that
25 new infrastructure whether generation or transmission is

1 brought online and then an OTC facility could retire. In
2 addition to just raw capacity, make sure the mix of both
3 these existing resources and any new ones that are
4 developed actually also satisfies the operational
5 flexibility of the ISO needs in order to actually manage
6 the grid effectively.

7 So generally the energy agencies, and by that
8 term I include the ISO and then for the purposes of
9 referring to Energy Commission, PUC and ISO altogether, we
10 want to be sure to tighten up our analytic planning and
11 permitting coordination in such a way that we can have
12 realistic expectations about what is the reasonable
13 options for these facilities in terms of replacement
14 infrastructure, get those options into our planning
15 processes, get decisions made, get permits issued, and do
16 that in sufficiently timely way that is reasonable from
17 compliance with ABC mitigation.

18 We're not at this point proposing any grand new
19 process in which all that happens but to tighten up the
20 linkages between our various analytic planning and
21 permitting processes. And, of course, we'll be doing this
22 in the context not just of dealing with OTC but with all
23 the other resource policies that the state has, the
24 constraints, the environment licensing presents either for
25 generation or for transmission, and we need also to be

1 doing this in the context of where the system is going to
2 go over time for GHG reduction.

3 As Mr. Bishop said, there's been active
4 involvement of the energy agency staff in the Water
5 Board's working group since last June. We've had
6 intensive discussions among the energy agency technical
7 staff since about September when after several months of
8 sort of getting comfortable with each other, as Mr. Bishop
9 said, I'd like for you to bring forward an actual
10 proposal. We turned up the effort level at that point and
11 have had a very intensive discussion since then.

12 We have put forward the sketch of a proposed
13 approach to the Water Board staff. It has been reviewed
14 by the managements of the various agencies. We've
15 received some feedback from the Water Board staff about
16 that, which we are taking to heart and are adapting our
17 initial proposal and submitting that back to the Water
18 Board staff.

19 As Mr. Bishop said, he expects to incorporate
20 this proposal into their policy, and we expect him to do
21 the same, so we think we're on the same wavelength about
22 our solution to reconciling OTC mitigation and
23 reliability. And you will see the proof of that in the
24 course of the next six or eight weeks.

25

1 So generally what is involved in this? We are
2 looking at the tradeoffs between generation and non-
3 generation options to replace the various OTC facilities.
4 There are some local capacity areas where there is an
5 existing surplus, but most of them are pretty tight, so
6 generally speaking, there's a pretty tight linkage between
7 no longer needing an existing OTC facility and bringing
8 new infrastructure into the picture.

9 In some instances, there is a pretty clear known
10 path by which that happens. The options in the specific
11 facilities are already well identified. A sort of trivial
12 example of this is the Humboldt plant. The Energy
13 Commission licensed a replacement of the Humboldt facility
14 and it's actually under construction. As soon as that
15 facility is complete, then the old can be removed.

16 Something not quite as tight as that but very
17 close to it, in the context of the South Bay facilities
18 down in San Diego, it's well understood that with
19 construction of the Otay Mesa Power Plant and the
20 operational status of the Sunrise transmission line that
21 Sunrise capacity will no longer be needed, and if its
22 owner should then wish to retire it, it would not be
23 necessary for reliability purposes.

24 For other facilities, there's more complicated
25 situations not nearly as well lined out replacement

1 infrastructure already in the pipeline, so that leads to
2 further analysis to identify the options and understand
3 the relative merits of each of the options, the timeline
4 associated with those options, and then pursuing one or
5 more of those options through processes at the PUC in
6 procurement or transmission being one of those options
7 first at ISO and then again back to the PUC if it's a
8 significant enough facility.

9 Some of these options may come through the
10 Energy Commission through its generation licensing
11 process. Some may have, in fact, already come through our
12 process, and merely be awaiting a long-run contract to
13 convert themselves into a real live project.

14 There are particular issues associated with
15 South Coast and for tradeoffs between the desire to
16 replace a lot of OTC capacity and the necessity of air
17 credits to satisfy South Coast's criteria pollutant
18 licensing processes. And then a particular additional
19 issue for LADWP, which is not, of course, jurisdictional
20 to either the PUC or the ISO and yet is within the South
21 Coast's airshed, so the Energy Commission staff is putting
22 particular focus on these South Coast's LADWP dimensions
23 of the issues.

24 So what comes next? Today's workshop is
25 receiving inputs from stakeholders that either validate or

1 refute, you know, various assumptions that we have been
2 making, so we're extremely interested in the input from
3 the stakeholders. We'll take that into account and
4 finalize our input to the Water Board.

5 As Mr. Bishop said, they plan on publishing
6 their proposed policy toward the end of June. Should that
7 be the case, then the current plan is to conduct another
8 workshop on July 9th under the auspices of the '09 IEPR to
9 go through the details of this electricity infrastructure
10 proposal. Clearly, they'll be included within the Water
11 Board's own policy paper and substitute environment
12 document, but probably not at the level of detail that the
13 people in this room are interested in, so by offering to
14 conduct another workshop under the auspices of the IEPR,
15 we can get more detail and subject that proposal -- that
16 part of their proposal to more scrutiny.

17 And that concludes my presentation. Are there
18 any questions from the Dais?

19 COMMISSIONER BYRON: No. Thank you, Dr. Jaske.
20 We'll press on so we can get any further discussion.

21 DR. JASKE: Thank you.

22 COMMISSIONER BYRON: Mr. Vidaver I think is next
23 with just the facts. You have the longest presentation I
24 think, David, but I'm sure it will go the fastest.

25

1 MR. VIDAVER: Fasten your seatbelts. I was
2 given an outline a lot longer than the time I was allotted
3 about a month ago. So the purpose of my presentation --
4 I'm David Vidaver. I'm with the Electricity Analysis
5 Office for the Commission. The purpose of my presentation
6 is to provide some consequence to the discussions that
7 follow by illustrating the magnitude of the role that OTC
8 has played on meeting California's capacity and energy
9 needs.

10 I'm going to present quite a bit of data. I'm
11 going to go through much of it very, very quickly. It
12 will be published in a staff white paper coming out in 30
13 to 45 days or so. And the interim if you really want to
14 burden myself or my staff, you can contact me and ask that
15 the data be sent to you.

16 What we're talking, as Mr. Bishop mentioned, 19
17 facilities totally over 20,000 megawatts, 17 gas-fired and
18 two nuclear. Almost all of these gas-fired facilities are
19 quite old, 1978 or earlier. The exceptions being the two
20 new units in Moss Landing and the Haynes and Harbor
21 combined cycles owned and operated by LADWP. There's 13
22 merchant plants, 6 utility facilities, the 3 LADWP
23 facilities, Humboldt Bay, which as Dr. Jaske mentioned, is
24 about to disappear, and the 2 nuclear facilities.

25

1 OTC plants constitute 35 percent of the capacity
2 and service of state loads and provide 19 percent of the
3 energy, the gas units 27 percent of the capacity and 8
4 percent of the energy, and the aging gas units 23 percent
5 of the capacity and 5 percent of the energy. And it's
6 these aging gas units that will be the focus of this
7 presentation.

8 As the numbers indicate, we're dealing largely
9 with low capacity factor units whose value lies not in
10 they're being an economic source of energy but a necessary
11 source of capacity. We do have four new or newer or
12 retooled facilities in Moss Landing and Haynes combined
13 cycles that I alluded to, and the Harbor Facility and the
14 Huntington Beach 3 and 4, which were retooled existing
15 units. As a colleague of mine said, if you take a 25-
16 year-old car, no matter how much you overhaul it, you
17 still have a 25-year-old car. That was his description of
18 Huntington Beach 3 and 4. My apologies to the owner.

19 MR. JASKE: But the owner agreed.

20 MR. VIDAVER: The energy from aging gas-fired
21 OTC plants has fallen by it looks to be about 60 percent
22 over the last six years. The energy from the Haynes and
23 Huntington Beach combined cycles has obviously increased.
24 The energy from aging OTC gas-fired plants has stabilized
25 over about the last four years, and we surmised that

1 absent the construction of new capacity in local
2 reliability areas that amount of energy isn't to fall
3 anytime soon.

4 These plants are needed largely during the
5 summer. The energy from these plants, pardon me, is
6 needed largely during the summer. AS you can see, that
7 during non-summer periods it's needed as well in part
8 because a large share of these facilities are in local
9 reliability areas. Here are the 2008 capacity factors for
10 these plants in descending order. I'm going to go through
11 really quickly. The first here are nuclear units. The
12 next two are the new combined cycles, Humboldt and
13 Potrero, that have higher capacity factors than all the
14 other aging facilities. And then we have everything else
15 and we're going to discuss. Well, we're not going to
16 discuss the nuclear units. We're going to get right to
17 the new combined cycles.

18 It's really tough to illustrate how a plant
19 operates both over the course of a year and the course of
20 a day in single graph, so this is sort of what you're
21 stuck with. This is the hourly generation of the Haynes
22 combined cycle last year. You can see it ramped between
23 350 and about 550 megawatts on a continuous basis. The
24 aspects of this graph that you should note are the density
25 of the data points up at 550. That indicates that it's

1 not a lot of hours at full output. You see some density
2 at 350, so it spent quite a few hours down there. And you
3 see nothing along the horizontal axis, so this plant was
4 not shut off at night.

5 That's what its low duration curve looks like if
6 you're more familiar with this. You can see that it spent
7 about half of the year at 500 megawatts or above. It had
8 set points of 350. It was off about ten percent of the
9 time and that was, as the previous graph showed, in
10 December. While we're talking about new combined
11 cycles --

12 COMMISSIONER BYRON: And if I may, Mr. Vidaver?

13 MR. VIDAVER: Yes, Sir.

14 COMMISSIONER BYRON: Can we assume then when
15 it's operating that it's pretty much at full capacity in
16 terms of its cooling?

17 MR. VIDAVER: I'm not the person to talk to
18 about the relationship between water consumption and
19 output.

20 COMMISSIONER BYRON: Okay.

21 MR. VIDAVER: I guess you have someone else far
22 more qualified than I am to do that.

23 This is one of the combined cycles at Moss
24 Landing. You can see it operated in a similar fashion to
25 the combines cycle at Haynes. The difference being that

1 the Moss Landing combined cycle was shut off on occasion.
2 You'll see quite a number of data point down along the
3 horizontal axis.

4 Just to knock off the last new unit. This is
5 the Harbor combined cycle cobbled together in 1984 by
6 LADWP. You can see that the department relies on it for
7 energy during very brief periods over the course of a
8 year. The density of the points at full output indicates
9 that it was ramped up to full load and left there, and the
10 low duration occurred accordingly and it looks like this.

11 So now that we've dismissed all the new units,
12 let's start talking about local reliability. Sixteen of
13 the nineteen facilities are in one of the five ISO defined
14 transmission constrained areas, the local reliability
15 areas, or the LADWP control area, which is effectively an
16 local reliability area due to local operating requirements
17 for the LADWP plants.

18 North to South, we have the Humboldt LRA, the
19 Greater Bay Area local reliability area, the Big Creek
20 Ventura local reliability area, the smaller circle showing
21 Los Angeles, which comprises both the LA Basin local
22 reliability areas defined by the ISO, and the LADWP
23 control area, and finally we have San Diego. If you're
24 not in a local reliability area and you're an aging plant,
25 and there are exactly two facilities, which meet that

1 description, you could not run very much. This is the
2 output of Morro Bay 3 and Morro Bay 4 that shows the
3 similar operating profile. This is Moss Landing 6. Moss
4 Landing 7 shows the similar operating profile.

5 Potrero 3 is in the San Francisco subarea of the
6 Greater Bay Area Local Reliability Area. It is the one
7 unit in the Bay Area that runs a lot. The capacity
8 requirements of San Francisco proper require that Potrero
9 3 be on virtually around the clock. Because of its slow
10 start nature, it can't provide capacity in the middle of
11 the day without -- It can't provide capacity at all
12 without operating, and it can't provide capacity during
13 the day without being left on overnight due to its slow
14 start nature. So of all the OTC units of the Greater San
15 Francisco Bay Area, Potrero 3 is the one that produces a
16 lot of energy in order to meet local reliability needs.
17 In contrast -- In contrast, the two units at Pittsburg and
18 the two units of Contra Costa produce very little energy.
19 This is the chart for Pittsburgh 5, Pittsburgh 6, Contra
20 Costa 6, and Contra Costa 7. All look very similar.

21 Now before we go on to dash through Los Angeles
22 and San Diego, we need to talk a bit resource adequacy.
23 As Dr. Jaske alluded to in his presentation, systemwide
24 zonal and local capacity and stability requirements have
25 to be satisfied, so we need quite a bit of capacity to

1 meet these requirements in the local reliability areas.
2 And as Potrero 3 indicated, the slow start nature of the
3 aging OTC units requires that they be operated at minimum
4 load levels to meet the spend and reserve requirements
5 later in the day. Some are used year round and others
6 primarily in the summer when loads are higher.

7 Now left to their own devices and to participate
8 in the energy market, these units would not be profitable,
9 and as California doesn't have a long-term, (inaudible)
10 capacity market, resource adequacy requirements imposed by
11 the PUC on load-serving entities in the ISO control area
12 lead to contractual agreements between either the load-
13 serving entity or the ISO and the generator, which allow
14 the generator to meet going forward with capital costs.
15 The generators may agree or disagree with that
16 characterization.

17 But most of these aging units have RA
18 requirements -- excuse me, RA contracts, which are
19 contracts between a load-serving entity and the generator
20 requiring that the generator respond to ISO orders to
21 dispatch in order to maintain local reliability. These
22 contracts can be with one of the investor-owned utilities,
23 it can be with the energy service provider, or it could
24 even be with a public utility in the ISO control area.

25

1 For example, El Segundo has a contract with the City of
2 Anaheim.

3 In the event that the utilities cannot reach
4 agreements with a sufficient amount of capacity for RA
5 purposes, the ISO can enter into RMR contracts directly
6 with generator of up to one in duration, which requires
7 that the generator respond to ISO request to dispatch. Of
8 course, it's always possible that a unit could be
9 efficient enough so that a generator would want the right
10 to dispatch it as part of its own portfolio. And then we
11 have four units under a legacy DWR contract that Southern
12 California Edison is administering in the Los Angeles
13 Basin.

14 So with that being said, here's an example of
15 how much capacity is currently under contract. There's
16 about 38,700 megawatts of merchant OTC capacity, 11,200 or
17 just over 80 percent of that is currently under contract
18 of one form or another. And as you can see, that number
19 declines over time and there is currently, to my
20 knowledge, no plant that has a contract that extends
21 beyond 2013.

22 I'm going to quickly run through the operating
23 profiles. There's a number of the Los Angeles and San
24 Diego units. This is LADWP Scattergood 1 unit. You can
25 see that it's needed year round, and you can see that it

1 runs almost entirely at minimum load. LADWP's need for
2 the capacity of Scattergood is such that they have to have
3 it available around the clock because the slow start
4 nature requires that it be operating in the middle of the
5 night to be available during the next day. That's what a
6 low duration curve looks like for a unit that performs
7 that service.

8 Scattergood 3 is needed during the summer,
9 again the slow start nature. Encina 5 in the San Diego
10 local reliability area has a very similar profile, as is
11 South Bay 3. A plant with multiple units may operate
12 one of those units in one fashion in order to meet local
13 reliability and another unit in a completely different
14 fashion. Encina 1 is very seldom needed in contrast to
15 Encina 5.

16 Huntington Beach 1 apparently has two set
17 points. Alamitos 3 runs on minimum load of about 25
18 megawatts. Alamitos 2 doesn't run at all. Redondo Beach
19 8 and all the Redondo Beach units run this rarely. Of
20 course, that doesn't mean that Redondo Beach is any less
21 necessary to meet local reliability needs than even the
22 more frequently running that's in Alamitos.

23 One of the options -- Well, the options facing
24 the OTC plants in the face of Water Board policy would be
25 to refit with acceptable cooling technologies, to repower,

1 or replace onsite, or to retire with any replacement
2 capacity if it was necessary that they build in another
3 location.

4 As Dr. Jaske said, staff has concluded that the
5 cost of refitting or such that most merchant plants --
6 most if not all merchant plants or at least aging
7 merchants plants there were required to refit would retire
8 unless the costs were recovered somehow through long-term
9 contract or some form of contract. There have been
10 several studies done on the potential for refitting these
11 plants and the cost of doing so. They're referred to
12 here. At the bottom, you can see the URL at which you can
13 locate these studies if you're interested,
14 waterboard.ca.gov.

15 EPRI found retrofit costs between \$17 and more
16 than \$675 million. The total cost of retrofitting all
17 these facilities would be in the neighborhood of \$4
18 billion. This least this is a very contentious number as
19 the next slide will indicate. All parties generally agree
20 that there are other penalties. The \$4 billion is the
21 capital costs. Refitting these plants would lower their
22 heat rates, result in higher operation and maintenance
23 costs, and lower their capacity I believe. EPRI concluded
24 that if you refitted all of the plants that could be refit
25 you'd lose about 400 megawatts in capacity.

1 EPRI found wet cooling that, while theoretically
2 possible, is a high degree of difficulty. Tetra Tech
3 found that, while wet cooling retrofits were technically
4 feasible, that feasible facilities still faced hurdles.
5 If you talk to the generators, as we will this afternoon,
6 you might find that many of them disagree about the
7 potential for refitting their facilities and the likely
8 costs of doing so.

9 And finally, the nuclear plants are about 60
10 percent of the energy from OTC plants in total, so we
11 can't ignore them. They would be the most costly to
12 retrofit. They would experience the most significant
13 performance penalties, and as Mike alluded to earlier,
14 some areas are harder to figure out from a planning
15 perspective than others. The Los Angeles Basin is
16 difficult to get a handle on in part because San Onofre
17 plays such an important role both in the Basin and in
18 Southern California in general.

19 The options for refitting, retrofitting, or
20 retiring, and replacing once-through cooled plants in the
21 Los Angeles Basin will likely depend on whether one
22 assumes the presence or absence of San Onofre. And the
23 ability to import power into energy into Southern
24 California is in part a function of whether or not San

25

1 Onofre is there and operating, so that analysis is one of
2 the more complicated facing the energy agencies.

3 COMMISSIONER BYRON: Any questions?

4 MR. VIDAVER: I believe that's it. If there are
5 any questions?

6 COMMISSIONER BYRON: Mr. Vidaver, thank you. I
7 think that, even though you've just presented facts and
8 data, I suspect that your presentation will generate a lot
9 of response on the part of the participants. Let's save
10 those for the panel discussion.

11 MR. VIDAVER: Thank you.

12 COMMISSIONER BYRON: Thank you very much.

13 MS. KOROSSEC: Next, we'll hear from Dennis
14 Peters from CA ISO.

15 MR. PETERS: Good morning. My name is Dennis
16 Peters with the ISO. I'm the External Affairs Manager.
17 And my role here today in this presentation is to give you
18 what the current and perspective role of OTC plants are in
19 reliability.

20 COMMISSIONER BYRON: Good.

21 MR. PETERS: I can tell you it's significant.
22 As Mr. Mansour indicated in his opening comments, it's not
23 a compromise. In terms of my presentation of it, I'll
24 just be speaking to those plans that are within the ISO
25 balancing authority area. Those are 16 of the 19 plants

1 that are affected by the policy, and I'll be speaking to
2 system reliability, local reliability, and the importance
3 of these plants in the integration of renewable resources.

4 So just to kind of set the stage for once-
5 through cooling policy in terms of the ISO's objective, we
6 need to maintain grid reliability in compliance with
7 federal standards while meeting the state's environmental
8 goals. And I apologize. I'll have to take a lesson in
9 PowerPoint from Jonathon Bishop. I don't have the balls
10 spinning in the air. But as you can see, not only is
11 once-through cooling something we're trying to work with
12 regard to reliability, we all know about the lack of air
13 credits in South Coast Air Quality Management District and
14 possibly other areas. There was is, you know, of course,
15 the integration of 33 percent renewables, as well as the
16 greenhouse gas AB32.

17 I was in a discussion with I'd say some veterans
18 in the energy business recently, and they said, you know,
19 trying to balance all these balls while maintaining
20 reliability is like rocket science. And someone responded
21 back, they said, no, it's actually more difficult than
22 rocket science.

23 COMMISSIONER BYRON: Mr. Mansour, I note that
24 the gentleman on the tight wire is well dressed and not
25 unlike yourself.

1 MR. PETERS: So you've seen these maps before.
2 I don't need to go through the details. You've seen them
3 in the previous presentations, but you know once-through
4 cooling cool generation represents a significant amount of
5 in-state generation. As for the ISO balancing authority
6 area, it represents 38 percent of the installed generation
7 capacity. That's a significant amount. And, of course,
8 the other three plants are in LADWP balancing authority
9 area.

10 I'll be going through each of these, the next
11 bullet items, in more detail, but it's needed for meeting
12 system demand, as David Vidaver had mentioned in his
13 presentation, essentially resource adequacy and that's
14 supply to meet demand that's needed for local reliability.
15 That's in reference to local capacity reliability areas.
16 I'll get into some detail on that. And thirdly, it's
17 essential to the renewable integration or the use of
18 procurement of ancillary services for ramping capability,
19 regulation, and load following.

20 This graphic here I'll spend just a little bit
21 of time explaining it. As you can see in the title,
22 nonnuclear, this is excluding the nuclear, but it's
23 nonnuclear, once-through cooling plants contributed
24 greater than 25 percent of supply to meet our 2008 peak
25 demand, and this is similar for years going back as well.

1 If you work your way down from the top, at the
2 very top, these are once-through cooling units with less
3 than 20 percent capacity factor. Next down is once-
4 through cooling plants with greater than 20 percent
5 capacity factor. And you can see a significant amount in
6 the highest peak load hours in 2008 those units were
7 required, so if there's any perception that low capacity
8 factor plants are not important to the reliability and to
9 keeping the lights on, this graphic will show you that
10 they are. They absolutely are. You know this is the
11 total -- The graphic kind of gives you the entire supply
12 picture to meet demand in those hours, and as I said says
13 25 percent comes from the once-through cooling plants
14 needed to meet system demands.

15 COMMISSIONER BYRON: Mr. Peters, so the x-axis
16 on the curve there, that's just the -- those are in rank
17 order and it would just be the first 30 or so either,
18 what, hours or days or?

19 MR. PETERS: Those are hours where peak -- where
20 the demand was within 93 percent of peak demand.

21 COMMISSIONER BYRON: So your highest --

22 MR. PETERS: Highest hours.

23 COMMISSIONER BYRON: -- 30 hours in the year?

24 MR. PETERS: Yes, correct.

25 COMMISSIONER BYRON: Thank you.

1 MR. PETERS: Okay. I'd like to spend a little
2 bit of time with this slide here. You know, David Vidaver
3 went through some of the, you know, issues of local
4 capacity requirements. I'll get to that \$5 billion number
5 in a minute that's in the top of the slide. But I'd like
6 to just kind of explain a little bit about local capacity
7 requirements. It's really subset of overall resource
8 adequacy, and it represents the capacity that needs to be
9 procured in specific local areas. It represents the
10 minimum resource capacity needed, and I'll emphasize this,
11 that were available, you know, in a local area to safely
12 operate the grid, and it's sort of a load pocket concept.

13 And you know, we mentioned we have ten local
14 reliability areas in the ISO's balancing authority area.
15 The once-through cooling resources that are in five of the
16 local capacity reliability areas represents an average of
17 58 percent of the capacity in each of those areas. And
18 that averages in those five areas anywhere from 46 to 61
19 percent. And David had already gone through which five
20 those are, so I won't repeat those.

21 So basically, it's a load pocket concept. Load
22 in a certain area may exceed the maximum transmission
23 capacity available to deliver resources into that area.
24 And when we do these studies, we do this every year, and
25 it's in addition to our transmission planning process, we

1 have several criteria to follow. We have national
2 reliability criteria through the North American Electric
3 Reliability Council, and through our Regional Western
4 Electricity Board Meeting Council planning criteria, as
5 well as what's MORC, or Minimum Operating Reliability
6 Criteria.

7 And so you can see this is a significant impact
8 if these plants were to retire and not be replaced or
9 retrofitted. It's a significant impact to reliability.
10 What we did last fall was take a look at what would be the
11 cost to replace, and that's sort of my item on the top
12 there. What would it take if we were to shutdown the
13 nonnuclear once-through cooling plants, and we actually
14 included in this study given that Humboldt was being
15 replaced right now, and I think we even included El
16 Segundo before the priority reserve issue came up down
17 there. But just to replace those plants if they were to
18 retire so, of course, this is a worst-case scenario, would
19 require \$5 billion in high-level transmission upgrades.
20 These are 500 kV lines as well as local transmission
21 upgrades in each of the local capacity reliability areas.

22 What's not in that number is the replacement
23 power that would be needed at the other end of that line.
24 So if you build a transmission line into, you know, the LA
25 Basin, you need something on the other end of that. Not

1 only do you need to replace some power on the other end of
2 that, you also need things, you know, like static VAR
3 comps there to support voltage within the LA Basin.

4 That aside, the cost of, you know, transmission
5 and the cost of replacement power is a lengthy process to
6 approve transmission, and as you could imagine, given that
7 most of these plants are in the LA Basin, it would be very
8 difficult and a very lengthy process to build that
9 transmission and get it permitted.

10 Sort of the last role in reliability that I want
11 to touch on was the role of the once-through cooling
12 plants, particularly the nonnuclear units because the
13 nuclear units are used for base load generation. As you
14 can see in David's graph, they run from, you know, 80 to
15 90 percent capacity factors of the base loaded plants.
16 Last fall the ISO released our Integration of Renewables
17 Report. We identified the need ancillary services
18 including regulation and inter-hour load following to meet
19 the 20 percent. That was just to meet the 20 percent
20 Renewable Portfolio Standard. And we determined, yes,
21 there was enough capacity there to provide those services.
22 And as I said, it's the nonnuclear OTC plants that provide
23 the services.

24 Replacement generation, this is a really key
25 point, any replacement generation needs to have similar

1 operating characteristics. They have to have the
2 capability to have low minimum load, have the ability to
3 ramp up very quickly, and to be able to ramp the different
4 operating points.

5 Right now, we're engaged in a study to see what
6 we would need to support the integration of 33 percent
7 Renewable Portfolio Standard. I think it's probably just
8 clear, I don't even have to say this, but you know more
9 fossil-fired generation will be needed to provide the
10 ancillary services we need to support 33 percent
11 integration, you know. And many have said, well, once,
12 you know, the once-through cooling plant goes away, it's
13 replaced by the renewables coming in. Well, no, it not.

14 We all know as most of us know in this room in
15 the business that renewables are intermittent. The wind
16 tends to blow at night. We tend to see maybe two the
17 three percent of winds supporting our peak load. We have
18 significant ramps in the morning when the wind comes off
19 and the load is coming up. The sun doesn't always shine
20 and it doesn't shine at night, so these plants are
21 critical to renewables integration.

22 So some considerations moving forward,
23 retrofitting, repowering, otherwise, replacing some
24 existing plants in the same areas. I guess commonsense
25 would just tell you that, you know, the best solution is

1 repowering or retrofit at the existing site. These are
2 located in, like I say, five of them are -- or sixteen of
3 them are located in local reliability areas. Brownfield
4 sites are obviously the best option.

5 But we also need to identify transmission
6 upgrades. As we move forward if plants repower, then
7 we're going to have to identify the transmission upgrades
8 as needed to maintain grid reliability. There's
9 definitely going to need to be coordination on the
10 nuclear, you know, plants with the Nuclear Regulatory
11 Commission oversight of the cooling retrofits.

12 And finally, as I kind of end where I started,
13 this is truly a balancing act coordinating once-through
14 cooling implementation with other environmental
15 initiatives, greenhouse gas, renewable integration, the
16 issue of acquiring air credits. These are all issues that
17 make this an even more complex issue for us to maintain
18 grid reliability. That's all I have. Thank you.

19 COMMISSIONER BYRON: Thank you, Mr. Peters. I
20 don't think we have any more questions. We'll press on
21 with our last presentation. Thank you.

22 MR. PETERS: Thank you.

23 MS. KOROSK: Next, we'll here from Robert
24 Strauss from the PUC.

25

1 MR. STRAUSS: Good morning. I'm Robert Strauss
2 from the PUC. The PUC regulates the independently owned
3 utilities. They do not have the ability to build new
4 power plants by itself. We don't built power plants. We
5 don't retire power plants. We can't force the retirement
6 of a power plant. Our main --

7 COMMISSIONER BYRON: Mr. Strauss, I think we'll
8 just -- we'll just correct that just because I don't think
9 you meant you regulate the independents. You regulate the
10 investor-owned utilities.

11 MR. STRAUSS: Correct, the investor-owned
12 utilities.

13 COMMISSIONER BYRON: Yes. Thank you.

14 MR. STRAUSS: And the three major investor-owned
15 utilities Pacific Gas and Electric, Southern California
16 Edison, and San Diego Gas and Electric represent
17 approximately 80 percent of the load-serving entities and
18 provide for about 80 percent of the power in California,
19 so they're a major power.

20 So the PUC has been -- The IEPRs in the past
21 have instructed or encouraged the PUC to replace the aging
22 power plants, which include the large owned OTC plants, as
23 David Vidaver spoke earlier. The PUC has been working for
24 that, and three of the projects that have been mentioned
25 are now under construction are the Humboldt, the PG and E

1 project, the Potrero, which is the transmission solution,
2 and the South Bay Power, which is both transmission and a
3 generation solution. The PUC wasn't the sole person these
4 plants were involved with, ISO analysis, there was utility
5 analysis, and participation. There's a lot of work that
6 went on by a lot of entities.

7 But the PUC's main activity here, I mean, in the
8 OTC has three basic functions. One is resource adequacy
9 program, the second is approval of transmission projects,
10 and the third is the procurement. So I'm going to be
11 speaking mainly about procurement today.

12 The PUC has approved projects in the last couple
13 of years for replacement of power plants in some local
14 areas that would reduce the need for some of the current
15 OTC plants. David Vidaver had a chart showing the
16 contracts for OTC plants and how they decline very steeply
17 over the next three years. Well, there's not going to be
18 new power plants built in the next few years to replace
19 those plants, so those plants are going to need to be re-
20 contracted for some period until replacement power can be
21 built.

22 MR. MANSOUR: Just again, some clarification.
23 Go back to the last slide. Which of the projects are you
24 saying that are under construction than Potrero's OTC?

25 MR. STRAUSS: Well, it's the Trans Bay Cable.

1 COMMISSIONER BYRON: Just transmission.

2 MR. MANSOUR: But that is just one unit of
3 Potrero. That's unit three.

4 MR. STRAUSS: Right. It's the OTC --

5 MR. MANSOUR: There is no project for --

6 MR. STRAUSS: It will eliminate the use OTC at
7 Potrero.

8 MR. MANSOUR: Okay.

9 MR. STRAUSS: The other units at Potrero do not
10 use OTC.

11 MR. MANSOUR: Not end the use. You're saying
12 end the use of what you see at Potrero. That is not
13 correct. That's correct?

14 MR. STRAUSS: No. It will end the OTC at
15 Potrero because the intent is to close Potrero 3, which is
16 only unit at Potrero that currently uses OTC. The other
17 units are all air-cooled.

18 MR. MANSOUR: Okay.

19 MR. STRAUSS: The PUC has stated its desire in
20 its long-term procurement plan decisions to reduce OTC,
21 but the main thing is the cost involved and system
22 reliability, so we're trying to balance the environmental
23 goals with the system reliability and cost. As you heard
24 earlier, the cost of replacing these plants is
25 significant. If you closed all these plants and stop

1 contracting with them immediately, there would not be
2 sufficiently reliability to run the system, so it's a
3 balance to try to make it work. We've been working
4 cooperatively with ISO and the CEC and the Water Board to
5 try to make this whole thing work well.

6 The PUC procurement process is basically to
7 analyze the resource needs and priorities. That includes
8 input from the CEC and the ISO for the reliability
9 transmission needs coming forward. The utilities file the
10 long-term procurement plans. They go through a very
11 involved regulatory process. Eventually, the Commission
12 approves that and approves a residual need. The utilities
13 then go out to a competitive process to be able to meet
14 that need, and the Commission reviews contracts and
15 hopefully approves those.

16 In that analysis process, the loading order,
17 which is the energy efficiency, demand response, and
18 renewables, and distributed generation are the priority.
19 That's one of the main lead priorities in going forward
20 with the long-term procurement process along with the
21 market.

22 Now the long-term procurement process takes into
23 account the state priorities, OTC, the preferred
24 resources, resource adequacy to calculate what we call
25 residual need. It's the amount of fossil that's needed.

1 It's residual because the priority is with the preferred
2 resources, so the residual need of the fossil is what
3 needs to be built of fossil resources to keep the system
4 running and ensure reliability and to do that at the
5 lowest reasonable cost.

6 The utilities take an authorization to build --
7 the residual need to build new generation. They go
8 through a procurement process that has a lot of regulatory
9 review process, a lot of oversight to ensure that it's a
10 fair and competitive nature. The main key here is that
11 these OTC plants are in a very good location. They're
12 needed for local reliability, but there are other options.
13 We want to go to the market to decide what are the best
14 options. Is repowering a plant the best option? Is
15 building a new plant the best option? Through a
16 competitor process, we can help determine that and what
17 the market decides.

18 The RFO contracts finance the building of new
19 power plants. I said we don't have the ability to permit
20 a new power plant, but by having utility rate payers fund
21 the contract or the Commission approves a contract for
22 buying power from a power plant that will provide the
23 basis for a finding so that a new power plant can be built
24 or an existing one repowered. And it talked about the two
25 different types, the short-term ones, which would be with

1 existing plants to give them the financing to keep
2 operating until replacement power can be in place, and
3 then long-term ones to build new power plants and to
4 obviate the need for using once-through cooling. The RFO
5 process takes six to the eighteen months, but there's a
6 lot of variables that are involved in that and it takes a
7 long period of time.

8 In the December 2007 decision that authorized PG
9 and E to go out and build over 1,000 megawatts of new
10 power plants, they went forward and issued an RFO. They
11 signed one contract, which they filed an application for
12 approval before the Commission in March. They've got
13 other contracts coming on that, but you can see the
14 duration of that process of going through the complexity
15 of trying to select the right contract, the right
16 resources that will meet the needs of the area.

17 Once a contract is signed, it goes through a PUC
18 approval process. The utilities file an application and
19 parties intervene. That can take six months to twelve
20 months depending on the complexity of the process and
21 whether hearings are needed, and that's basically it. Any
22 questions?

23 COMMISSIONER BYRON: No. Thank you very much,
24 Mr. Strauss. Let's go ahead and move to our panel. I
25 guess it's actually made up of some different folks.

1 Maybe we should stop for a moment and see if
2 there's any questions, brief questions, clarify, or
3 whatever from any members of the audience that would care
4 to ask. I know I may be jeopardizing our schedule, but I
5 think there was a lot of material that just went through.
6 Again, if you could just limit yourselves to clarifying
7 questions if you need any.

8 MS. KOROSSEC: If you do have questions, come up
9 to the podium in the center, please.

10 COMMISSIONER BYRON: Right. All right.

11 MS. KOROSSEC: There's none online. Does anybody
12 have some questions? No. We've had none.

13 COMMISSIONER BYRON: Okay. We'll proceed.

14 MS. KOROSSEC: All right. So will the panelists
15 for panel one please come up to the front table?

16 COMMISSIONER BYRON: I'm sorry, Mr. Jaske --
17 Dr. Jaske.

18 DR. JASKE: So the agenda for the remainder of
19 today's workshop will have panels composed of various
20 similar -- close to similar backgrounds. So this first
21 panel is the environment agencies, and you've already
22 heard from Mr. Bishop. We also have Mohsen Nazemi from
23 South Coast AQMD, Mike Tollstrup from State Air Resources
24 Board, and Al Wanger from the Coastal Commission.

25

1 And in order to sort of make sure everyone fully
2 understands the issues behind what these various entities
3 have as their responsibilities and what their situations
4 are, unlike the panels this afternoon, we gave this group
5 an opportunity to make sort of some opening statement
6 about the nature of their organization or the issues in
7 front of them. And Mr. Nazemi did ask to make such a
8 presentation, so before we get to the questions, Mohsen,
9 if you could run through your brief presentation. Give us
10 some common background.

11 MR. NAZEMI: Good morning. My name is Mohsen
12 Nazemi. I'm Deputy Executive Officer for South Coast Air
13 Quality Management District. And I appreciate the
14 invitation by Dr. Jaske and also the opportunity to give a
15 very brief overview. I think you already this morning a
16 number of references to potential problems and offsets in
17 South Coast Air Quality Management District. Our agency
18 is a regional local air pollution control agency, which
19 governs over all of Orange County and the non-desert
20 portions of Los Angeles, San Bernardino, and Riverside
21 Counties with a population of 16 million, almost half of
22 the state and unfortunately the worst air quality in the
23 nation.

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COMMISSIONER BYRON: Sorry, Mr. Jaske, Doctor
Jaske.

MR. JASKE: So the agenda for the remainder of
this workshop, we'll have panels including various
similar, folks with similar backgrounds so this first
panel is environmental agencies and we've already heard
from Mr. Bishop. We also have Mohsen Nazemi from South
Coast AQMD, Mike Tollstrup from State Air Resources Board,
and Al Wanger from the Coastal Commission. And in order
to make sure everyone fully understands the issues behind
what these various entities have as their responsibilities
and what their situations are, unlike the panels this
afternoon, we gave this group an opportunity to make sort
of some opening statement about the nature of their
organization or the issues in front of them and Mr. Nazemi
did ask to make such a presentation. So, before we get to
the questions, Mohsen, if you could run through your brief
presentation, give us some common background.

MR. NAZEMI: Good morning. My name is Mohsen
Nazemi and I'm Deputy Executive Officer for South Coast
Air Quality Management District. And I appreciate the
invitation by Dr. Jaske and also the opportunity to give a
very brief overview. I think you already heard this
morning a number of references to potential problems in

1 offsets in South Coast Air Quality Management District.
2 Our agency is a regional/local air pollution agency which
3 governs over all over Orange County and non-desert
4 portions of Los Angeles, San Bernardino, Riverside County,
5 population of 16 million, almost half of the State and,
6 unfortunately, the worst air quality in the nation.

7 One of the primary responsibilities we have is
8 permitting of various stationary sources including power
9 plants. And as part of permitting of power plants, one of
10 the cornerstones of our regulations which is actually a
11 federal/state law that we implement for regulations is
12 called new source review or NSR. You've heard of other
13 acronyms this morning. I'm going to add one more to it --
14 NSR.

15 NSR applies in offsets. Emission offsets are
16 required whenever there are new facilities built or
17 relocated or monitor stations of existing facilities.
18 However, under our New Source Review program and, in
19 particular, in relation to utility repowering we have, for
20 decades, had exemptions in our program from offsets
21 requirements whenever a power plant using needing to
22 replace some of the old utility borders that gas turbines.
23 We had exemptment (sic) done from requiring the offsets
24 provided there is no increase in capacity.

25

1 However, in the early 2000, due to the
2 California energy crisis and, later on, in the middle of
3 2000, based on projections, the Energy Commission made
4 about shortfalls in summertime in Southern California. We
5 also amended one of our other New Source Review rules
6 referred to as priority reserve rule to allow power plants
7 also to access our bank of credits for new power plants or
8 for repowering where they're actually increasing their
9 capacity as well as just replacing the units.

10 However, because these exemptions do not exist
11 under federal and state law, our agency still has to
12 provide these offsets and we use what we call our internal
13 offset bank to provide the offsets for these types of
14 projects. And, in order to do that, we have been, for two
15 decades almost, running a new source review tracking
16 system where, again, in early 2000 EPA asked us to adopt
17 that into a regulation as well.

18 Once we did that, a number of environmental
19 organizations, natural resources that has counsel,
20 communities, better environment and others filed two
21 lawsuits, one in August of 2007 challenging our amendments
22 of our priority to reserve, Rule 1309.1, to allow power
23 plants to access our bank of credits and also our new
24 source review tracking rule, Rule 1315.

25

1 In July and November, again in 2008, Judge Ann
2 Jones of the State Supreme Court ruled in favor of the
3 environmental organizations invalidating both those rules
4 due to CEQA issues. And in August of last year, another
5 lawsuit was filed by the same group of organizations,
6 environmental organizations and this one was a federal
7 lawsuit challenging the validity of all of the offsets in
8 the district's internal bank.

9 So, what happened, as a result of this court
10 decisions, State court decision, we are not able to permit
11 any projects that were relying on these internal banks, in
12 particular, essential public services, other local
13 government business projects and, in addition, no new or
14 repowered power plants can be permitted using our internal
15 bank.

16 The only remaining avenue left for these
17 projects including the power plants to obtain permits is
18 to provide their own emission reduction credits or ERCs
19 where they can buy in the open market. So what's the
20 problem with that?

21 The problem is that there's not enough ERCs in
22 the open market and, in addition to that, they're not only
23 expensive but they're essentially unaffordable. Now,
24 without the ability to move forward some of these
25 projects, as you've heard earlier, you have 8032

1 greenhouse gas reductions that use new renewable portfolio
2 issues that will be delayed since these projects can't
3 move forward. In addition, we have over 1300 permits
4 pending that cover a variety of essential public service,
5 local government and other businesses.

6 As a matter of just background, this is about a
7 dozen or so projects that are pending. These are all
8 power plants proposed in South Coast with the exception of
9 the last two down in Antelope Valley and Mojave desert
10 area. But all of these power plants were relying on being
11 able to obtain credits from the district's internal bank
12 and the first three projects listed above are actually
13 obtained through power purchase agreement with Southern
14 California Edison about 1900MW that cannot move forward at
15 this point.

16 The next couple of projects are 1200MW. We
17 actually denied those permits and they are undergoing CEC
18 licensing process at this point and CEC is looking what to
19 do with those two projects.

20 The remaining 2000MW are all pending. Just to
21 give you an idea, you see a couple of municipality
22 projects here. One Canyon Power Plant for the City of
23 Anaheim, it's a small sized project, 200MW. They just
24 ended up spending \$16 million just buying emission
25 reduction credits for a 200MW project. The City of

1 Riverside also has a 99MW project just find the ERC
2 transfer for those. They accrued up to about \$6 million
3 just for emission reduction credits. So, you can see that
4 this is very expensive and not potentially affordable.

5 Also, the two projects in the High Desert area,
6 the Victorville and Palmdale, because of the scarcity of
7 offsets in their district, they had also, under State law,
8 they can request or we can approve, transfer our credits
9 from our district to their district. And they wanted to
10 transfer some credits to be able to permit or license
11 their projects.

12 So, to give you an idea why there is a problem
13 with credits, if you look at this bar chart, the white bar
14 chart shows the availability of ERCs for the most
15 (inaudible) particulars of PM10. And as you can see,
16 between 2000 and 2008, the amount of credits available in
17 the market dropped in almost half of what it existed eight
18 years ago.

19 The blue bar chart, on the other hand, is the
20 price of credits. And, as you can see, the price
21 increased by almost fifty-fold and, in fact, this slide
22 shows the highest price paid for PM10 in 2000 April is
23 \$247,000 per lb/day. In 2009, we actually have \$320,000
24 per lb/day.

25

1 And, just to show you why there is a scarcity or
2 there is a, trouble in South Coast, that mustard colored
3 bar chart is beyond, is only the amount of credits we
4 have by those three power plants in the previous slide
5 that have obtained power purchase agreements with Southern
6 California Edison. And only to provide credits for those,
7 you can see it is more than twice the ERCs in the open
8 market. So there doesn't even exist enough ERCs. And I
9 had to find out that many of these ERCs are held by
10 companies that don't fall under any of our exemptions. So
11 they have plans for their own expansions in the future.
12 So, even though they are valid ERCs, they are not willing
13 to sell them at any cost because they have their own
14 projects.

15 Doctor Jaske asked me to give you an indication
16 so if there isn't enough ERCs in the open market, is there
17 enough in the district's bank to cover that?

18 To give you an indication, our bank consists of
19 credits that goes back to Pre-1990 and in our new source
20 review tracking system, we have been reporting these
21 credits to EPA on their Resources Board, like I said, for
22 over almost two decades. And the number of credits that
23 we have been reporting are shown in the first slide.

24 As a result of early 2000 requests by EPA to
25 adopt our new source review tracking into a rule, we

1 actually negotiated and discussed the validity of these
2 credits and EPA wanted us not to use any of the credits
3 that we no longer hold the records for. And,
4 voluntarily, we agreed to do that. So you can see that we
5 reused our bank account for PM10, in particular, by 92%
6 percent in early 2000 when we discussed this with EPA.

7 And, as a result, I think today, if you look at
8 what took place in early 2000 during the California energy
9 crisis, almost 4900MW of new generation was built at that
10 time. Unfortunately, or as a result, 3,000MW of old
11 generation was taken out of service. But you can see
12 that, at that time, before we introduced our bank, the
13 amount of credits used by power plants was less than 2%
14 percent of our bank. So it really had no effect on our
15 bank.

16 But even today, if we look at all the pending
17 projects within AQMD and the two projects outside the
18 AQMD, Mojave and Antelope Valley, the amount of credits
19 that's needed for these 4,000MW in South Coast and other
20 1100 outside, depending on which pollutant you look at, is
21 anywhere from 1% percent to 14% percent of the bank.

22 Now, I do need to, again, remind you that there
23 is a federal lawsuit pending that has not been ruled on by
24 the federal judge that is questioning the validity of
25 these credits. Now, these are important because as you

1 heard this morning, once through cooling in South Coast is
2 about a third of total gas power generation and many of
3 those projects are either owned by other MWD, AS or NRG
4 and overall, the gas power generation in South Coast, 50%
5 percent of the plants are over 40 years old and not that
6 it's old. I know many of us are over 40 years old but for
7 a power plant, that's probably considered old.

8 So, this brings us close to where we're going
9 with my last slide, where we're going from here. One of
10 the things that we have done since the state court
11 decision is we have appealed the state court decision
12 primarily because the State judge ruled that not only we
13 cannot use our bank of credits moving forward permitting
14 any other projects but any permit that has been issued
15 since we had adopted our Rule 1315 is also in jeopardy.
16 And, so we appealed that decision to put a stay on over
17 2,000 projects, almost 3400 permits that have been issued
18 between 2006 and 2008 when the judge made her decision.

19 We also initiated rule development to readopt
20 our new source review tracking rule. Most of these
21 appeals and re-adoption are not going to be quick.
22 They're going to take about a year and there's no
23 guarantee that once we re-adopt our rule, there is no
24 further challenges. We have participated in mediation

25

1 with the litigants and environmental organizations. So
2 far, we have not come to any agreement under mediation.

3 And, lastly, we have proposed legislation under
4 Senate Bill 696 which is sponsored by Senator Rodney
5 Wright. What this legislation does is reinstates the
6 amendments to Rule 1309.1 and 1315. It does require power
7 plants -- and I know these are some of the questions that
8 Doctor Jaske's going to ask of the panel -- to meet very,
9 very stringent standards beyond what's typically required
10 of power plants in order to be able to access the credits
11 from our internal bank, requires power plants not to get
12 those or doesn't allow the power plants to get those
13 credits for free like essential public services. They
14 would have to pay a mitigation fee. However, our agency
15 has committed -- and we have done this with the previous
16 mitigation -- to reinvest these in emission reduction
17 projects in their areas where these power plants are going
18 to be built.

19 And, finally, as part of this legislation,
20 because there was a significant concern from the
21 environmental groups that they did not want Southern
22 California with the worst air quality in the nation to be
23 the mecca of all power plants to everybody comes there and
24 builds, we have included in this proposed legislation the
25 requirement for the Energy Commission to do a needs

1 analysis to indicate whether or not that power plant is
2 actually needed to be located in southwest area. And that
3 concludes my presentation. Thanks for the opportunity.

4 COMMISSIONER BYRON: Thank you, Mr. Nazemi.
5 The, I'm probably remiss. I probably should have
6 introduce Arthur Jaske. I had asked him if he would
7 moderate this panel, take us through a series of questions
8 and I very much appreciate the panelists that have made an
9 effort to be here today. We've got the right folks here,
10 Mike, I think to help answer some of these questions.

11 MR. JASKE: As Commissioner Byron said, my role
12 here is to work us through these questions and also end
13 this some time so we can take lunch. At the expense of,
14 there's follow-ups that occur to me so I'll pursue that.
15 So, let's start with the very first question and this
16 actually, the first (inaudible) of these are mostly
17 oriented towards to the Water Board. So, Mr. Bishop, if
18 you'll -- clearly, what the agencies are proposing implies
19 that if you will to some degree or considerable degree of
20 respect for, with its history of reliability. Does your
21 agency think it has the discretion to encompass that in
22 its proposal?

23 MR. BISHOP: Well, the short answer is yes. The
24 longer answer is the Water Boards, in general, have the
25 biggest area of flexibility in implementation. They're

1 much more constrained on, in meeting a certain goal but
2 once that goal is identified, we have, I think, a lot of
3 flexibility in how we get that, to that goal. So, as I
4 stated earlier as we talk along, as you were talking
5 (inaudible), we're very open and hopeful in essentially
6 incorporate a more flexible implementation schedule. It
7 still needs (inaudible).

8 I will make one interdiction in this I always
9 have to say which is that our Board deals very strongly in
10 deadlines and so the need to have a milestone or
11 accountable is very important to our Board and will have
12 to be incorporated as we move forward.

13 MR. JASKE: I would like to ask you about one
14 facet of milestones. Earlier today, in my own
15 presentation, I indicated that because some projects, new
16 infrastructure was, are you implying that would mean
17 particular OTC plants that might no longer be needing to
18 prove reliability sooner in time than others and that
19 implies, in effect, a different compliance with a, for
20 different group of plants or even as specific as
21 individual plants. Is that kind of approach presenting
22 the issues in developing your goal?

23 MR. BISHOP: You know, once again, the short
24 answer is no. The longer answer is that we can identify
25 different compliance dates for different plants or

1 different groups of plants or even different units within
2 a plant if we feel that's appropriate. We just have to
3 justify that (inaudible).

4 MR. JASKE: Moving to question two, in reference
5 to California Water Code in, among the things in the
6 section of the Water Code that appears to, in some
7 respects, provide or require for the balancing of
8 considerations; is that the right to think about it and is
9 reliability, you know, to be thought of in that sort of
10 balance fact?

11 MR. BISHOP: Oh, we, as remotely many
12 (inaudible) space, we have been working somewhat on
13 legislative performance and (inaudible) certain times. We
14 are, on one hand, required to minimize the impact of the
15 power plants but we also are required to take into account
16 the impacts of our rules on the California eco-society as
17 a whole and, as such, we always are in that balancing
18 mode.

19 We can't, on one hand, trade off one impact for
20 the other and say we will not address this because it has
21 other impacts. We have, what we've been charged to do is
22 to figure out how to minimize the impacts in both ways.
23 So, in terms of regional liability, we include and are now
24 going to require, have large requirements need to bring
25 stability in the grids. We are committed to that. We are

1 moving on, going to move that forward. At the same time,
2 we can't say because of impacts to the grid, we are not
3 going to regulate once through cooling. So we have to
4 walk that line between them. I feel we have the
5 flexibility to do that, working on that front.

6 MR. JASKE: Would you be at all concerned if the
7 US EPA were to resurrect its rule making activity and they
8 have a different legislation requirement in that their,
9 the flexibility that you're talking about a lot might not
10 exist in the USEPA rule?

11 MR. BISHOP: I can't speak for the USEPA but my
12 experience with their rule making is that they will have
13 a, if their rule making results in less flexibility for
14 us, we are likely to be found compliant. We can be more
15 stringent than the EPA in most instances but not the last
16 time. The air folks might have a little disagreement on
17 that on some issues but for us, that's normally the case.
18 My expectation is that if you would take the numerous
19 (inaudible) quite a while to come up with a new approach
20 and I wouldn't expect to see something out of that in a
21 while.

22 MR. JASKE: We'll get to question three. I
23 recall that your presentation this morning mentioned the
24 Supreme Court decision of April 1st. It wasn't clear in
25 your presentation whether you were, you mean that outcome

1 as something that (inaudible) did or did not alter the
2 trajectory of business the Water Board staff is on the
3 issues that are involved.

4 MR. BISHOP: Well, that's probably because I
5 wasn't clear on it. I wasn't clear because it's not a
6 clear-cut direction what the latent -- my legal counsels
7 advised me is that it's such that the USEPA may take into
8 account cost. So, we will likely mimic that in some way
9 and try to develop a criteria for which that may be
10 considered. We don't expect to change or cause the
11 wholesale to address it but we would expect to acknowledge
12 that this report has said that that may be a factor in
13 trying to lay out some criteria that a power plant could
14 use or usually could use to make that argument. My
15 expectation is that would be to a regional board with an
16 appeal process (inaudible).

17 MR. JASKE: So, question four now, sir, to open
18 things up potentially to the rest of the panel, so
19 clearly, the Water Board's general approach that we talked
20 about this morning has reached through the lens of the
21 energy agency's interpretation of also new infrastructure
22 is going to be necessary. You talked about that directly
23 so, I guess, generally speaking, when new kinds of
24 infrastructure generation or turning emission projects of
25 sort of major size or perhaps or distributive generation

1 that, you know, evolved outside of our jurisdiction but
2 still require some sort of permit from the local agency.
3 Do your agencies, you know, have any issues with the
4 permitting process that is for all of this new
5 infrastructure? Is there any way that you could build on
6 your earlier approach?

7 MR. BISHOP: Sure, thank you. I think the
8 reason that I wanted to give that earlier presentation was
9 that for a simple answer to a question, I don't have to
10 speak on five minutes but, in general, I think you realize
11 that our agency has looked at this issue awhile ago and,
12 in fact, when we adopted new regulations to control air
13 pollution or criteria of pollutants in our basin, that was
14 when we started to consider that if old utility boilers
15 which is less efficient, is dirtier and more polluting has
16 to be replaced with a new, more efficient and less
17 polluting cleaner technology that needs to become a
18 facilitation under our regulations. So, we have, for
19 decades have had this exemption under our rule to allow
20 that to take place.

21 Furthermore, when we realize that a power plant
22 may need to be located at a location different than where
23 it used to be located, given some transmission
24 restrictions, of course, in consideration to that, we
25 began to look into amending our new source review further

1 to allow those new power plants to be built. And, we do
2 have, as we indicated, Arthur Jaske, regulatory authority
3 over permitting of not only just central generation but
4 also the distributed generation.

5 However, through our work with the Air Resources
6 Board and their distributed generation and certification
7 program, with the exception of very few technologies such
8 as fuel cell and other micro-turbine technology, in
9 general, distributed generation is dirtier compared to a
10 central power plant because their inability to use the
11 most sophisticated control technologies. And so, although
12 you would be shredding the generation through a larger
13 area but when you look at it per megawatt or per kilowatt
14 of power generated, there's a greater amount of emissions
15 or criteria with the smog forming compound in general.

16 So, even though we have the jurisdiction, we do
17 look into tighter standards for distributive generation.
18 But with the advent of the AB32, I think everybody looking
19 at renewables such as biogas, landfill gas and other types
20 of technologies as well. So, we are facilitating those
21 but with the lawsuit and the court decision in front of
22 us, we have a very difficult time moving those types of
23 projects forward at this time.

24 MR. JASKE: This is a follow-up. In the normal
25 course of business or distributed generation facilities

1 that are, you know, smaller scale that would come to the
2 Energy Commission, those facilities commonly require ERCs
3 purchased from the market or do you have a program that
4 allows them to use, you know, internal bank credits?

5 MR. BISHOP: What we allow under our resource
6 review program is for small emitting facilities that have
7 emissions of less than 4 tons per year, we provide them an
8 exemption from requirements of providing offsets.
9 However, our internal bank then is used to cover the
10 offsets from those projects. You may recall Southern
11 California is including four 49MW units in Southland a
12 couple of years ago and those were all utilized those
13 exemptions. So they didn't need to provide ERC but yet,
14 we provided those ERCs from our internal bank.

15 I guess, the big difference is that with the
16 larger power plants where we allow them to access our bank
17 even though they're under 4 tons, what happens is we still
18 provide the credits from our bank to offset those emission
19 increases but the difference is that the money that they
20 pay is not through a third party. They pay a mitigation
21 fee to the district which we, in turn, turn around and
22 reinvest it in emission reduction projects in the
23 community where these power plants are being built.

24

25

1 MR. JASKE: Mr. Tollstrup, do you have anything
2 you want to add to that answer, particularly with respect
3 to smaller scale distributive generation?

4 MR. TOLLSTRUP: Well, I think there are a couple
5 of things here. I think that essentially, a lot of the
6 focus is on South Coast because the issues have kind of
7 come to a head here but there's a larger issue of concern
8 and that's the need for offsets and, you know, to start
9 programs in the (inaudible). I think, eventually, it
10 would concern some of the other districts which face
11 various similar problems as the South Coast does.
12 Certainly, with the distributive generation projects,
13 South Coast does have a priority to reserve or did have
14 that allowed them to access that, to obtain mitigation.
15 In other areas of the state, that option isn't necessarily
16 there. There's (inaudible) on the open market and then he
17 was charged with total prior offsets and you'd have to go
18 out there and purchase these ERCs in the open market.

19 The OTC is just kind of a subset of the larger
20 issue that needs to be dealt with. And as Mohsen pointed
21 out, the, a lot of these DG projects, distributive
22 generation, aren't necessarily as efficient or as clean
23 as some of the larger central station projects.

24 So, it depends on how much goes forward in a lot
25 of the areas in the state addressing it and what kind of

1 budgets received will see them. But it is an issue, I
2 think that will come up in other areas. It's just a
3 matter of time.

4 MR. JASKE: Why don't both of you expand upon
5 certain stands that these power plants in the Mojave
6 district using credits from South Coast?

7 MR. NAZEMI: In terms of projects outside our
8 basin, under state law, there's a provision that you can
9 transfer credits from an upwind down district to a
10 downwind district provided the, non-attainment status for
11 the bailment district is significantly contributed by the
12 upwind district.

13 In the case of both Mojave desert and Antelope
14 Valley, that is the case as determined by State Air
15 Resources Board so the provisions exist for the transfer
16 of these credits. And, in those two districts, there is
17 practically no ERCs available. I understand that there
18 may have been some created recently by the shutdown of a
19 powered cement plant, however, in general, they don't have
20 a bank of credits either internal or third party type
21 credits and so, in the past, we have transferred credits
22 for the High Desert project that the California Energy
23 Commission licensed through the transfer of credits from
24 our agency and, therefore, this is the provision that we
25 felt like was already allowed under state law and so the

1 changes we made to our new source review, prior reserve
2 rule was to allow credits to be transferred again to the
3 district's downwind in order to allow construction of
4 these projects.

5 Our Board, however, does not endorse wholesale
6 transfer of open market ERCs from our agency down to these
7 two, down the districts because as I showed you on the
8 slide earlier, that there's hardly enough credits
9 available out there for projects that are not exempt from
10 losses and they need economic growth. They need to have
11 credits in the open market and we can't just allow one or
12 two power plants to just buy all the credits in the open
13 market and transfer it down to their district because our
14 Board feels that that is not going to help the economy of
15 Southern California.

16 MR. JASKE: So, in terms of these credits,
17 credits from winds, downwinds, gathering from what the two
18 of you said that that's allowed by state law but is there
19 discretion on the part of the upwind districts to permit
20 that to happen, to agree that that transfer should take
21 place?

22 MR. NAZEMI: Yes, actually, in the state law,
23 there is a requirement that both upwind and downwind
24 district Governing Board has to have approved that we're
25 making a number of findings. So there is a requirement

1 that both of the Boards make certain findings and then,
2 approve that to transfer the credits. However, just to
3 close on that, the changes that we amended into our new
4 source review rule which was adopted by our Governing
5 Board, did incorporate an approval of the transfers from
6 our internal bank to the downwind districts, not from the
7 open market.

8 MR. JASKE: But if there is to be transferred,
9 it's not market ERC; it's internal bank credits. I think
10 this is a good time to ask you, Mr. Wanger, to give us a
11 little bit of an explanation of the general role the
12 Coastal Commission and, perhaps, you'll give us what was
13 originally required here is that as proposed. Mr. Nazemi
14 referred to one of them. If I understand the Coastal
15 Commission recently acted on the fifth on one of those.

16 MR. WANGER: Excuse me, the Coastal Commission
17 has a responsibility on Coastlec to review any project in
18 the coastal zone for its impact on coastal resources and
19 compare those with the particular resource policies in
20 Coastlec. Clearly, the, (inaudible) is that the Energy
21 Commission has the sole authority for permitting and
22 locating modified power plants with a grade of 50MW and as
23 we've been talking about most of these plants that are
24 under this, potential end of this policy, clearly are over
25 50MW.

1 However, under the Coastal Act, the Commission
2 has express authority to participate in Energy Commission
3 proceedings and make a series of findings of how a
4 proposed project can be done in conformance or compliance
5 with the requirements of the Coastal Act. And, so we
6 would analyze the project to make a report with findings
7 to the Energy Commission on how particular project impacts
8 could be mitigated or addressed as part of the Energy
9 Commission's proceedings. And then, because of, I guess,
10 according to the Warren-Alquist Act, the Energy Commission
11 must include those specific provisions in its final permit
12 decision unless it makes one or two findings -- if they
13 find that it's unfeasible or they would have a greater
14 environmental impact from the decision.

15 The Coastal Act can also be administered by
16 local government entities that have what's called a local
17 coastal plan. They've essentially prepared a plan to show
18 the Coastal Commission how it can take over a permitting
19 authority in their jurisdiction, how their application to
20 Coastlec would be compliant with the requirements of the
21 Coastlec in a local planning and permitting process. In
22 many of those cases and in most of the power plant issues
23 that would come forward in a local jurisdiction, the
24 Commission retains appeal authority to work on those
25 issues as well.

1 An example of how this played out in recent
2 years was the staff of the Coastal Commission worked with
3 the Energy Commission on the proposed project upgrades at
4 the Morro Bay power plant. The Commission made a series
5 of recommendations that the Energy Commission staff also
6 agreed with on how that project could move forward to look
7 at phasing out once through cooling as an impact.

8 There we saw, as Mr. Bishop reported earlier,
9 the findings that once through cooling has a significant
10 impact on marine resources is of great concern to us.
11 We're looking at the long term viability of coastal
12 resources, marine resources, looking for ways to reduce
13 those impacts. Obviously, we support the phase out of
14 once through cooling and have been pleased to participate
15 in this working group to try to find a way to achieve that
16 objective in a way that is considerate and thoughtful of
17 the needs of system reliability and to try to use the
18 planning and permitting, purchasing process that's
19 available through the energy agency's respective
20 authorities to achieve that goal and objective.

21 I think one of the questions that you had posed
22 to us was how do we perceive that, those issues coming to
23 us? We, I was thinking about that but there is one
24 probably one aspect in working with local jurisdictions
25 and establishing long range plans, for instance, bringing

1 a new transmission to an area that probably would want to
2 be incorporating those ideas and plans into their long
3 range development plans. So, it's probably a conversation
4 to be had with local jurisdictions and the Commission as
5 well on regional planning and local planning issues.

6 And, secondly, in being reactive to projects
7 that are brought for us, forwarded to us for a Commission
8 permit under the Coastal Act, we'd be looking to see how
9 this project conformed to the policy laid out by the Water
10 Board and how this project needs to be conditioned in a
11 way to make sure that those particular project aspects are
12 dealt with appropriately in a way that's in conformance
13 with the Coastal Act and, obviously, as I mentioned
14 before, in the old Coastal Act, we'd be making a report
15 back to the Energy Commission about here's how this could
16 be achieved in this particular case. I think that's the
17 primary reason (inaudible).

18 MR. JASKE: So, do you, I guess, I'm going to
19 ask this follow-up question. Since that the current
20 (inaudible) power player, power plants would retire early
21 and not be repowered in place and to allow that, there
22 would be at least transmission development and the Coastal
23 Commission would have a role in permitting that
24 transmission facility?

25

1 MR. WANGER: For those, the area that's within
2 the coastal zone itself, yes. Depending on the
3 particulars of the project, I can imagine multiple
4 scenarios reaching the 16 or so plants in our
5 jurisdiction. But, yes, we have a role in permitting in
6 that.

7 If we were part of a federal project, we might
8 have other authorities under the Coastal Management Act to
9 handle consistency review, to come in on that and just try
10 to work with the project proponents on conditions that
11 make that feasible for approval. But, yes, we would be
12 permitting, working on permitting transmission parties in
13 those particular areas.

14 MR. JASKE: Before we move on, Mr. Tollstrup, is
15 there anything more, you know, in this general area of
16 supporting new infrastructure that you want to make some
17 (inaudible)?

18 MR. TOLLSTRUP: You know, right now, there are a
19 lot of discussions internally to figure out how this is
20 going to be put together. There's no, there's no single
21 way of hacking this. I think that the, you know, we work
22 closely with the districts and there's EPA as well to see
23 if there's somebody to get right on some of the issues
24 that are raised that at this point in time, we're still

25

1 kind of scratching our heads trying to figure out which
2 way forward.

3 MR. JASKE: Thank you. Question five raises the
4 whole notion that if or "when" it is necessary for them,
5 the (inaudible) plants to file for the permitting of power
6 plants, then seemingly is this debate in (inaudible)
7 analysis. Is modification and state implementation plan a
8 feasible route to an impact, to create more power plants
9 presuming, I guess, that some others emission source or
10 sources were squeezed down tighter? Do you generally view
11 that as a viable route to follow as far as a solution to
12 new power plant builds?

13 MR. NAZEMI: I can take a stab at this. I think
14 the answer is yes and, again, the changes that have been
15 reflected in our regulations some time ago have all been
16 approved into the state implementation plan by USEPA. The
17 recent changes that we had incorporated in the 2000, early
18 2000, those were to allow again power plants to access our
19 bank of credits with basically no limitation and those
20 were approved into the SIP by the USEPA. And the most
21 recent changes that we have made that have not been
22 invalidated by the State judge, actually put in a much
23 more stringent requirement on both criteria pollutant
24 emissions and toxics emission depending on where the plant
25 is going to be located, significantly more stringent

1 requirements than those on power plants who want to access
2 our bank of credits.

3 And, you know, we have been working with the
4 processes that once we make changes into our rules, we
5 submit it to the Air Resources Board first and there is
6 actually requirements under state law that we can't make
7 our new source review rule less stringent so they evaluate
8 it and in this instance, they actually, the Air Resources
9 Board had, made that determination and forwarded these
10 rules over to USEPA corridor, approval into the state
11 implementation plan. But because of this court decision,
12 there is some question on whether EPA will act on this at
13 this point or not.

14 And, finally, I think it is important to point
15 out that our program on offsets in general was created
16 back in 1977 under the Federal Clean Air Act. Our agency
17 actually had adopted these types of requirements under new
18 source review earlier than the 1977 Federal Clean Air Act
19 amendment. I don't think anybody envisioned at that time
20 that this offset requirement would be such that first of
21 all, there wouldn't be any offsets or enough offsets
22 available for economic growth and, secondly, the price of
23 credits would be exuberant to the point that right now, as
24 I mentioned, we have some over a thousand permits pending.

25

1 These are like for back-up generators to be
2 installed at a police station and in order to get their
3 permit now, they have to purchase offsets in the
4 neighborhood of \$70,000 - \$100,000 just for the price of
5 emission reduction credits. So, I don't think there's
6 any, wasn't any intent that this be the process for
7 generating and providing offsets.

8 So our agencies began some work. We had to form
9 the workgroup including the Air Resources Board, USEPA,
10 our agency and the representatives of both industry and
11 environmental organizations to look into what other
12 solutions there are and initially make provisional changes
13 to our regulation and state implementation plan to address
14 that. And I think that's something that's not going to
15 be, again, quick. We have, we're looking at short term,
16 mid-term and long term approaches and depending on where
17 we end up with those, I think that time will show whether
18 they will be successful or not.

19 MR. TOLLSTRUP: And, I'll add to this one. I
20 see this as two issues here. One, you ask if can you
21 amend the SIP to put tighter controls on source and other
22 sources to allow for power plant growth? I think that
23 that's a real hard sell specially in areas like South
24 Coast, the San Joaquin Valley, there's certain areas who
25 can make that commitment under state federal law to get

1 reductions. And, quite frankly, in those areas, there are
2 not technologies there to get where they need to be. So,
3 I think that you can, you know, add additional control to
4 existing sources.

5 The districts have already adopted rules and
6 gone, you know, as far as they can on most sources though
7 they may be somewhat a few there but normally -- So, I
8 don't, that one just doesn't pass the straight face test.
9 I just don't think that given the real issues that they
10 have on those areas, this just would not work.

11 The second side of that is the new source review
12 side which Mohsen touched on. There is a provision in
13 state law that says that the state has to review the
14 district's NSR rules and the banking is included in that
15 review. And it basically says that, you know, you take
16 the rules that existed back in December 2002 and you look
17 at any changes they made in the requirement. If there's a
18 relaxation -- anytime, a relaxation -- we disapprove the
19 rules and the districts can't move forward on it.

20 So, anytime they go looking at -- and this is
21 part of the problem -- is that looking for flexibility or
22 trying to create additional reductions or additional
23 flexibility under new source review, you know, that, it's
24 going to be harder not to show that that isn't a
25 relaxation of the rules. So, you know, in trying to work

1 with the districts, we've been working closer to the South
2 Coast on a number of ideas. They have, the (inaudible)
3 passes the straight face test but I think there are issues
4 on both sides either controlling existing sources or going
5 beyond SAR (inaudible) that we have to, that we have to
6 deal with.

7 MR. JASKE: As indicated earlier, you provided
8 the other districts whose their credit situations are
9 blown up, publicized (inaudible) South Coast that might be
10 sort of on the horizon. Can you identify where those are?
11 In particular, are they, you know, in locations where all
12 these existing OTC plants are?

13 MR. TOLLSTRUP: Well, one that comes to mind
14 would be San Diego. San Diego's had issues in the past on
15 the, in fact, they were trying to get some power plants
16 built down there like I'll take Mesa. We have (inaudible)
17 the offsets for that project down there. That situation
18 has not changed. They still have an issue down there.

19 The other districts going up the coast, I don't,
20 I don't enough information to answer that but we suspect
21 that it will be an issue, eventually. Anytime you have to
22 provide offsets for a large stationary source (inaudible)
23 credits purchasing (inaudible).

24 MR. NAZEMI: Doctor Jaske, I think just a last
25 point to add to this. I think that it is important to

1 consider when, when I mentioned that our Governing Board
2 made changes, amendments to our rule to allow power plants
3 to access our bank of credits, again, it wasn't for the
4 sake of just building power plants in South Coast.

5 When we had an early 2000-2001 energy crisis, we
6 saw what happened. We saw a couple of diesel back-up
7 generators started to run and, you know, our agency's
8 responsibility is to protect air quality and public
9 health. We don't find that as a good solution to not
10 building power plants. So this time, when the Energy
11 Commission came up with a projection that there will be
12 again a shortfall in the coming summers, our Governing
13 Board felt that we better be pro-active rather than be
14 reacting to calls from Governor's Office to allow power
15 plants to track up their NS30 whole units and run over
16 their permit limits and requirements. So, we were trying
17 to prevent a worse disaster rather than just build power
18 plants in South Coast and that's why our Board adopted
19 these changes.

20 MR. JASKE: Oh, I think we largely crept to last
21 question, question six. Things are underway. You
22 indicated, Mr. Nazemi, that for example, the South Coast
23 is working right now to try to rehabilitate part of Rule-
24 1315 and 1304 through your own regulatory process and
25 you've also identified this legislation that South Coast

1 has sponsored. Are there other things that district
2 hasn't relayed, you know, that we should know about in
3 context of this question we're here today?

4 MR. NAZEMI: The only other thing I would add is
5 historically, emission reduction credits or ERCs have been
6 generated from sources like a factory, a power plant or
7 other type of stationary sources.

8 We are, as we speak, in the process of looking
9 at what other sources of emission reductions are there,
10 typically non-conditional sources that we are in the
11 process of actually developing a few regulations that
12 would allow additional ERCs to be generated and those
13 include road paving, one of the main ways to generate
14 emission reduction credits. The other one we're looking
15 at is we have Metrolink as one example. It operates on
16 (inaudible) engines on their trains where they pull into
17 the stations. They're running dunes typically are diesel
18 powered engines to provide light and air conditioning to
19 trains and we're looking at how we could, how we could
20 have those units replaced with cleaner technology and a
21 reductions, cleaner emission reductions.

22 And, finally, we've been working with a number
23 of sources at the port in terms of this is ships that come
24 into the port to look at abilities to once they hook up to
25 the dock, to shut down their boilers and diesel generators

1 and use either shore power, cold ironing and if they can,
2 in their units are now being provided that would go over
3 and beyond what their resources for regulation requires,
4 goes up the percentage of ships that have to be converted
5 to shore side power.

6 And, in addition, we are also we have permitted
7 a project where the air pollution control system that is
8 right now, it's on the shore side and what they do is that
9 they have a bonnet that's like the hood that they put on
10 the top of the stack of the ship as it's sitting at the
11 dock, running their engine, to pool all their emissions
12 they do and air pollution control system and they've
13 tested those units and they're in the 90 plus percent
14 efficiency in terms of reducing the air pollution and
15 consented by the use of these types of technologies, we're
16 looking at regulations to adopt to allow them to be also
17 bring their emission (inaudible).

18 MR. JASKE: Mr. Tollstrup, anything you want to
19 add?

20 MR. TOLLSTRUP: I think (inaudible).

21 MR. JASKE: Mr. Wanger? Anything else that
22 comes to mind in terms of the (inaudible) restrictions of
23 the Coastal Commission?

24 MR. WANGER: No, not much to add. I think we're
25 trying to work with local governments as much as we can in

1 looking at the long range development plans. I think any
2 of the new infrastructure as I mentioned in the forum
3 would begin to think about what those conversations might
4 be, how we could perhaps facilitate conversations with
5 local entities about proposed changes in infrastructure
6 within the area and how they can incorporate that into
7 their planning process for their communities.

8 I think it would be, specially for Coastal
9 Communities, they have a few other things on their plate
10 besides, besides this we see what issues their efficiency
11 level rise and their impacts on local economies and
12 infrastructure. And it would probably be yet another
13 important part of the conversation they need to have. So,
14 perhaps, we might talk about going about how we might
15 facilitate that conversation.

16 COMMISSIONER BYRON: Doctor Jaske, may I ask you
17 a couple of questions?

18 MR. JASKE: Okay.

19 COMMISSIONER BYRON: Mr. Nazemi, you'd
20 indicated there's other ways you're looking at creating
21 emission credits. I couldn't help but think that those
22 aren't necessarily stationary, trains and ships. Do those
23 fall under your jurisdiction?

24 MR. NAZEMI: You're absolutely correct that our
25 primary jurisdiction is stationary sources. However, the

1 emission reductions can be generated from mobile sources
2 on their own regulations. That doesn't mean we regulate
3 them but if they voluntarily want to come in and apply for
4 emission reductions, then we can regulate them on their
5 terms of either a permit to enforce the requirements or
6 some sort of an agreement to enforce the requirements.
7 Typically, the USEPA does not like agreements. They like
8 to be either a permit or a regulation and that's why we're
9 allowed some regulations.

10 COMMISSIONER BYRON: Too bad we can't go after
11 those mobile sources that's the biggest polluters of all
12 in this way, namely, automobiles. Mr. Wanger, you may
13 have addressed this so I may be repeating when I ask but
14 would the Coastal Commission seek additional conditions
15 other than the ones that addressed once through cooling in
16 repowering any existing power plants? Is that what you're
17 implying with your comments that there would be a number
18 of additional conditions that the Coastal Commission would
19 require for repowering?

20 MR. WANGER: Well, I think it depends on the
21 nature of the project itself if, for instance, there were
22 impacts from the project on sensitive habitat, aside from
23 particulars or if they affect public access or what
24 probably went on from the proposed development. And then,
25 we would look at conditions to address those issues but it

1 would be done in the context of here's the package of
2 things that we need to be done to bring this particular
3 project in conformance with the Coastal Act.

4 COMMISSIONER BYRON: Well, I think you know that
5 and certainly my tenure at the Commission, we're not going
6 to, we're not going to license power plants that have run-
7 off, have unmitigated impact on the environment. I think
8 what I'm trying to get to, specifically, is is this going
9 to be seen as an opportunity by the Coastal Commission to
10 essentially implement conditions on a repowering of a
11 coastal plant that would basically prohibit it from being
12 able to be repowered? In other words, are you going to go
13 after more than just once through cooling when you have
14 the opportunity to do so?

15 MR. WANGER: No, I don't think -- the short
16 answer is, John, (inaudible), no. I don't believe our
17 Commission would do that. We would, especially given the
18 constraints that we have in the Coastal Act and the
19 Warren-Alquist Act, we'd be making serious recommendations
20 about what we think would be the most appropriate set of
21 conditions for this project but we wouldn't be seeking to
22 impose those above and beyond what is necessary or is
23 allowable at the moment.

24 COMMISSIONER BYRON: Thank you. Thank you. Mr.
25 Nazemi, one more quick question, if I may? Do you see

1 this issue as once through cooling, is this issue -- I
2 call it the once through cooling priority reserve nexus
3 issue here -- do you see this issue being solved in the
4 absence of any kind of settlement of the parties in the
5 litigation?

6 MR. NAZEMI: Well, the, there are a couple of
7 other ways that this could be solved. One is, as I
8 indicated, there is legislation that is pending. In fact,
9 it goes to the (inaudible) committee tomorrow.

10 COMMISSIONER BYRON: Right. There's actually
11 two pieces of legislation but they only affect a limited
12 number of power plants.

13 MR. NAZEMI: Actually, SB696 affects all. It's
14 not limited. The other legislation, (inaudible)
15 legislation; you're correct. It applies to maybe just one
16 power plant. So that's one way but it's fail/pass and it
17 allows those repowering and new power plants to be able to
18 move forward.

19 The second way that this could be done is, as I
20 indicated, we are readopting our NSR tracking rule. Once
21 we have that rule, we adopt it and provided we withstand
22 any further challenges which probably (inaudible) to tell
23 about, what that rule does is allows -- it doesn't allow
24 for new power plants to be able to be built but if it is
25 an existing facility that is going, undergoing repowering,

1 that allows our exemption rule which has been in place and
2 has not been invalidated by this judge to utilize the
3 exemptions and through our new tracking rule, we would
4 account for those emission increases offset those
5 accordingly.

6 So those are the two ways beyond priority
7 reserve that include a lot of the once through cooling to
8 move forward.

9 COMMISSIONER BYRON: Thank you. Any questions,
10 gentlemen? Are we hungry? Doctor Jaske, thank you very
11 much. Is there any other questions that you want to ask?

12 MR. JASKE: No, Commissioner.

13 COMMISSIONER BYRON: Well, thank you all very
14 much. Let's go ahead and adjourn for one hour. We'll
15 restart at 1:30, on time. Thank you.

16 (Whereupon, a lunch recess was taken.)
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AFTERNOON SESSION

1
2 MR. VIDAVER: Welcome back. You all know
3 (inaudible). This Panel this afternoon is a discussion
4 with a group of representatives from Merchant Generators
5 participating in California's market. Regulatory agencies
6 will no doubt be around forever hopefully implementing
7 well informed decisions, utilities (inaudible) the
8 consequences as (inaudible). Merchant Generators may not
9 be here forever. They have the option of getting up and
10 walking away if the regulatory processees of redesign
11 don't facilitate investment in California's electricity
12 center.

13 MR. LEUZE: Mr. Vidaver, you make it sound like
14 their departure is only voluntary. Sometimes it's not
15 voluntary.

16 MR. VIDAVER: This is true. But nevertheless it
17 has to craft a regulatory process and environment in which
18 they can thrive (inaudible) last ten years might be
19 considered by some to be a waste.

20 So we have representatives from five entities
21 which own OTC Generation in California. I'm going to take
22 the liberty of introducing them. Eric Leuze from Reliant
23 is here. Reliant owns Mandalay and Orland Beach in the
24 Big Creek Ventura load pocket. Sean Beatty with Mirac,
25 which owns the three facilities in the San Francisco Bay

1 Area of load pocket. Randy Hickok with Dynegy, which owns
2 South Bay in the San Diego load pocket and Moss Landing
3 and Morro Bay the two units that are not located in a
4 local reliability area. We have Eric Pendergraft with
5 AES, which owns Alamitos, Huntington Beach and Redondo
6 Beach all in the LA basin local reliability area. And
7 Jesus Arredondo with NRG, which owns El Segundo in the Los
8 Angeles reliability area and Encina I believe in the San
9 Diego local reliability area. Each of these gentlemen has
10 agreed to appear here and respond to a series of
11 questions, which they received.

12 I'm going to go through them one at a time.
13 I'm going to slightly restate them so hopefully my
14 question will capture the essence of the question that
15 they are prepared the answer.

16 The first question deals with measures that may
17 have been taken at their facilities in order to comply
18 with any near term requirements for mitigating the impacts
19 of once through cooling. Near term being that period of
20 time prior to the implementation of the policy which
21 requires the elimination of once through cooling.

22 That being said there are a couple of ground
23 rules. As I mentioned earlier this is not a forum in
24 which we are going to debate the wisdom of the State Water
25 Board Policy and you may be tempted to talk about the

1 wonderful things that your facilities can do as currently
2 continued and the incredibly important role that they play
3 in meeting California's energy needs, but we'd appreciate
4 if you'd keep the cheerleading to a minimum. So with that
5 being said, I don't know how you want to do it. Maybe Mr.
6 Leuze who's sitting closet to me (inaudible) first.

7 MR. LEUZE: Thank you, Dave. My name's Eric
8 Leuze and our company is RRI Energy, formerly Reliant
9 energy. And first I would say we're committed to fully
10 complying with all applicable laws and regulations and to
11 minimizing the adverse environmental impact of operations.

12 With regard to the design of our facilities the
13 Orman (phonetic) station has an offshore intake with a
14 velocity cap and then excluder bars and these facilities
15 substantially reduce the impingement of (inaudible). The
16 Mandalay station is at the end of a manmade canal and
17 harbor system and so that largely reduces the impacts, of
18 course, if that pumping did not occur then there might be
19 some detrimental impact on the bay and the harbor.

20 With regard to measures that we might undertake,
21 I guess first I'd like to point out that both of these
22 plants were designed as base load facilities and over the
23 years due to the economics of their operation they operate
24 quite a bit less and the corollary is that the circulating
25 water pumps are not on as much and so when they're off

1 line there's no water being pumped through the facilities.
2 And as the ISO presentation illustrated, these facilities
3 are still critical to grid reliability operating at the
4 peak. And, of course, during those times they are pumping
5 water through the cooling system.

6 So that's the exiting design and exiting
7 operation. There are other measures that we could
8 undertake and were, did a preliminary look at measures,
9 such as variable speed drives to further reduce the
10 pumping volumes and associated environmental impacts when
11 the facilities are operating. Of course, the economics of
12 such investment would have to be supported by market
13 revenues, which maybe we can talk about a little bit
14 later.

15 MR. VIDAVER: Very well. Thank you. Mr.
16 Beatty.

17 MR. BEATTY: Thank you. Yeah, before jumping
18 into answering the question just a few high level remarks.
19 One is as we work through adopting a policy here with
20 respect to once through cooling is, and I think this will
21 become apparent as the generators go through their
22 discussion points is that there is uniqueness to each one
23 of the facilities and we really are concerned that the
24 effort to craft the one-size-fit-all approach is not the
25 right way to go.

1 And along those lines we think that if there is
2 a policy adopted, and I understand we're not here to
3 debate the merits of that policy, but if there is we think
4 a prudent thing to do is to make sure that there is some
5 kind of re-opener or re-look substantially too far in
6 advance to make sure that grid reliability is assured to
7 prior to any of these planning going out flying. So those
8 are the two high level points I just want to make quickly
9 before jumping into the answer.

10 With respect to merits specifically, since 1994
11 we've actually retired nine of our once through cooling
12 units that comprise about 1300 megawatts of capacity, and
13 those units were once (inaudible) so they're no longer
14 online and therefore, they no longer draw water from the
15 Delta, so there's significant environmental impact
16 production right there.

17 We still operate five units in California that
18 rely on once through cooling. There's two units in Contra
19 Costa, two units at Pittsburg, and then of course, the
20 infamous Portrero facility. At those units we've deployed
21 variable pump technology, which scales the volume of water
22 used to the amount of electricity being generated.

23 We also, in the Delta units, which are the
24 Pittsburg and Contra Costa plants, we operate subject to
25 the Delta dispatch requirements, which essentially state

1 that there's a preferential dispatch order that relies on
2 Pitt unit, Pittsburg unit seven, which is a non OTC plant,
3 before dispatching the once re-cooled plants that are
4 there. As a result we've seen a 90 percent reduction in
5 the use of water in our Delta plants since the early '90s.
6 So that's kind of the historical view of what's going on
7 at those particular units.

8 And I really think that's an important point
9 because listening in to some of the discussion about the
10 once through cooling bill, SB42, there was statistics that
11 were used that dated back to 1978 the created a fairly
12 bleak picture and the fact that we reduced water usage by
13 90 percent would suggest that the data from 1978 is really
14 not germane to the discussion at this point.

15 And then finally, in terms of the types of
16 things we're looking at going forward is we have looked at
17 the possibility of using cooling towers at the Delta units
18 and that review is preliminary, but we recognize, you
19 know, kind of the direction that the State is headed and
20 we're trying to evaluate all the possibilities.

21 MR. VIDAVER: Mr. Hickok.

22 MR. HICKOK: All right. I'm Randy Hickok. As
23 you said, I'm with Dynegy. We've got three coastal power
24 plants, South Bay, Morro Bay and Moss Landing. And
25 regarding what we're currently doing to reduce the impacts

1 of once through cooling. Morro Bay and South Bay have
2 rotating screens, (inaudible) bars, obviously that's per
3 the water permits, there are several limits on the
4 differential, the (inaudible) water (inaudible) plants and
5 leaving the plant.

6 We also did have units one and two at Morro Bay,
7 which we put into mothballs I want to say somewhere around
8 five years ago now. So water circulation at the Morro Bay
9 plant is down (inaudible) from any stats that would have
10 been germane in the '80s.

11 At Moss Landing, Moss Landing is in my mind like
12 having two plants. We've got 1500 megawatts worth of
13 conventional boilers then we also have about a 1,000
14 megawatts of combined (inaudible) power plant we built up
15 in the parking lot around 2002. And they have separate
16 (inaudible) structures. Units six and seven have
17 protected measures similar to that of Morro Bay and South
18 Bay with the inlet screens. I know that prior to our
19 taking possession of Moss Landing PG&E had finished
20 retiring unit one through five and relocating the outcall
21 structure from the Elkhorn slough out into Monterey Bay.
22 Thermal limits are in place.

23 What's unique about Moss Landing would be the
24 new combined (inaudible) and we have one of the few
25 combined (inaudible) plants that was permitted recently

1 using once through cooling. The intake structures there
2 are slanted screens type so they have lower intake
3 velocities than our other facilities with that similar
4 restrictions on thermal impact. One of the aspects of
5 Moss Landing units one and two was part of the CEC
6 conditions to get our AFC and build the plant required us
7 to pay mitigation that the intent of which was a one-time
8 payment to offset the detrimental impact to marine biology
9 over the life with the (inaudible). So those payments
10 were made back in 2002 to the Elkhorn Slough Foundation
11 that purchased a lot of land then there's been some
12 mitigation around the Elkhorn Slough.

13 We've got a lot under study, but nothing that's
14 (inaudible) to so consequent.

15 MR. VIDAVER: Mr. Pendergraft (inaudible).

16 MR. PENDERGRAFT: Hello. Eric Pendergraft with
17 AES. We own Alamitos, Redondo Beach and Huntington Beach,
18 all in the LA basin about just over 4200 megawatts I
19 think, depending on what statistics you use. It's just
20 short of 20 percent of Southern California Edison's peak
21 demand.

22 We have velocity caps in place on Redondo and
23 Huntington Beach intakes. There are, you know, studies
24 indicate that they reduce impingement by approximately 80
25 percent. The canal intakes at Alamitos are manmade, as

1 Eric cited, for one of the Mandalay plants so they don't
2 limit themselves to that velocity cap installation.

3 You know, as we've seen today the units run a
4 lot less than they were designed for. If we look back at
5 our 2008 operating profile and take our actual sort of
6 circulating water flow volumes, which should be
7 proportional to entrainment and impingement. We're about
8 70 percent below what the plants are permitted to run at.

9 And I think there's still a little misconception
10 or misperception out there that when the plants are off
11 line we do in fact shut down our circulating water system.
12 Those pumps, except for very unique circumstances, the
13 pumps are shut down and there are no entrainment and
14 impingement impacts when our pumps are not operating.

15 The other thing you saw I think with David this
16 morning is these facilities spend a fair amount of time
17 operating at minimal loads so they're therefore spinning
18 reserve. We've been experimenting with, each of these
19 units are supplied by two circulating water pumps, and
20 this is a little bit of a poor man's veritable speed drive
21 experiment. But we've been experimenting with shutting
22 down one of those circulating water pumps when we're at
23 minimal low, which would directly reduce the impacts by 50
24 percent. And given the amount of time we spend operating
25 at minimal low that has a pretty significant benefit.

1 We have performed high level retrofit studies
2 for closed cycle cooling, both wet and dry cooling. As
3 one might expect there are significant land constraints as
4 well as permitting issues. They're expensive, you know, a
5 rough ballpark for wet cooling at our sites it's
6 approximately \$125 or \$115 a kilowatt. So for our 4,000
7 megawatts you're looking at, you know, 500 million
8 dollars, half a billion dollars to retrofit with wet
9 cooling. It's about double that for dry cooling if you
10 could in fact get it permitted and built.

11 We've heard about the associated efficiency and
12 other impacts so I won't highlight those.

13 Like Dynegy we spent five and a half million
14 dollars on a wetland restoration project to offset our
15 entrainment impacts for Huntington Beach three and four.
16 That restoration project is just about completed. For the
17 first time since I have been around we've got title closed
18 in the wetlands that's adjacent to our plant, so that's
19 pretty encouraging.

20 And then finally, we are bartering with West
21 Basin Municipal Water District to do a desalination
22 demonstration project. Part of that demonstration study
23 will include testing one millimeter and two millimeter
24 wedge wire screens. So that's a yearlong study. It's,
25 you know, being basically done by the Municipal Water

1 District given that they're a public agency. Those
2 results will be public, which answers one of the questions
3 here, so that's another technology installation that's
4 we've seen evaluated as part of the desal [sic] project
5 so.

6 MR. VIDAVER: Mr. Arredondo.

7 MR. ARREDONDO: Jesus Arredondo for NRG.
8 Similar to what my colleagues have already said, NRG has
9 engaged similar practices, velocity, caps that actually
10 have proven very effective at our El Segundo facility
11 reducing entrainment and impingement by more than 90
12 percent. Pump shut downs whenever it has been
13 practicable, we've done that as well.

14 At our Encina facility, which is North San Diego
15 County, we've coordinated our operation whenever possible
16 with Hub Sea World. We host a white sea bass hatchery.
17 So whenever there's planned releases that typically occur
18 once a year, we do try to coordinate as best as possible
19 to avoid any entrainment and impingement. That's what we
20 have.

21 What we're doing today, the future NGR we have I
22 think discussed (inaudible) at this Commission because we
23 have gone through at least one AMC proceeding now all the
24 way through. One that is newer for El Segundo despite
25 having actually obtained an AMC for continued use of

1 (inaudible) and came back to the Commission and
2 voluntarily opted to update our permit and this time come
3 back around appealing for a permit modification to non
4 once through cooling in the future.

5 Now unfortunately, while we have secured a,
6 participated in RFO and secured a contract that went
7 forward for ten years it's been (inaudible) in the south
8 coast, their quality management (inaudible) problems and
9 we're participating in that process of trying to identify
10 a solution legislatively hopefully to explain the success
11 alluding to that. I think that you are too.

12 The Encina project, that AFC we came in to the
13 Commission and that one we're coming in for a non once
14 through cooling in the future. And we have a little bit
15 of experience with transitioning in that we appealed to
16 the Commission and asked that the Commission not exert
17 it's jurisdiction when we retrofitted our Long Beach
18 facility for non once through cooling. We were under the
19 megawatts so the Commissioners, thankfully, obliged us and
20 said we won't exert jurisdiction.

21 So we're moving forward and looking to the
22 future, but it's very important to note that while NRG has
23 been able to do this at our facilities something critical
24 that Dynegy and others will agree on this Panel, one size
25 does not fit all policy to impact. All of this will not

1 work for all of us. NRG has been able to do it because we
2 have the space and because we've chosen specific
3 technologies that might not be good for others and where
4 the space might not be available at other facilities. But
5 at least for us moving forward without once through
6 cooling is something that's hopefully going to happen and
7 the sooner the better obviously.

8 MR. VIDAVER: Thank you (inaudible).

9 MR. HICKOK: David, could I --

10 MR. VIDAVER: Yes, sir.

11 MR. HICKOK: -- could I fall back a minute to
12 talk about what we're doing prospectively. I just
13 remembered --

14 MR. VIDAVER: Sure.

15 MR. HICKOK: -- what question two is all about.
16 Something we're doing, nothing regarding what we'll do
17 prospectively and our anticipation is that time will shut
18 down once it's no longer required for must run purposes
19 and that would predate 2015 or whatever the target
20 timeline is, so there's no activity at South Bay and Morro
21 Bay given the vintage of that plant and how seldom it
22 runs.

23 They're looking at what it would take to replace
24 the existing pumps with variable speed pumps right now
25 when the plants running. The pumps run at one speed. We

1 can replace that with variable speed pumps and we would
2 move less water in the plants. It's running at minimum
3 load versus max load.

4 At Moss Landing we're also looking at variable
5 speed pumps, although I don't think it'll make as big a
6 difference there because Moss has a number of pumps at the
7 plant and (inaudible) goes on sequentially as load builds
8 and the like so you'd be getting a little (inaudible)
9 benefit, but not a great deal at Moss.

10 At both Morro Bay and Moss Landing we'd be
11 looking at screen house retrofits depending on what water
12 speed you want across the screen. At both Morrow Bay and
13 Moss Landing we did a lot of very specific investigation
14 into those locations as part of the CEC permitting process
15 for units one and two at Moss and then we were hoping to
16 build a similar plant at Morro Bay.

17 So we already have in place a very extensive
18 record regarding the feasibility of using dry cooling, wet
19 cooling. We're in the process of dusting those studies
20 off and updating the cost, but I think we understand well
21 what's feasible and what's not feasible there. I think in
22 both of those plants due to PM10 issues wet cooling is not
23 an option and that Morro Bay given opposition by the City
24 of Morro Bay no closed cycle cooling is an option.

25

1 Two that are a little unique, at Moss Landing we
2 just sent a RFO out to the Moss Landing Green Laboratories
3 asking them to conduct a study as to whether water could
4 be drawn from deeper in the ocean. Right now we pull it
5 out of the harbor. The notion there is that 90 percent of
6 the living organisms in the sea water are located
7 relatively near the surface and so we're trying to discern
8 whether there is a location deep enough under the surface
9 of the ocean that we'd pull, it wouldn't be sterile water,
10 but it would have the (inaudible) less marine biology in
11 it than the waters that we're drawing off of right now.

12 And that might be viable at that location
13 because the trench (inaudible) Marine Canyon there
14 (inaudible) Monterey Bay drops off precipitously just a
15 couple of hundred yards off the shore, so that might be an
16 option open to that plant that isn't open to others.

17 And another crazy idea that we've got is what if
18 you just made a closed cycle cooling system, but have the,
19 effectible you'd be linking with pipe your intake and your
20 outtake structure, so you would be circulating water
21 through the plant. You would have no impingement or
22 entrainment, you would still have thermal issues, you
23 know. That's a wild enough idea that we're not sure
24 whether from an engineering standpoint it's even viable,
25 but we're checking it out.

1 MR. VIDAVER: Thank you. Well it's a, you
2 proceeded to ask, you know, answer a good part of the
3 second question. The (inaudible) it's dated that's right.

4 MR. MANSOUR: And just the kind (inaudible)
5 actually some of the data, some information which is
6 (inaudible) from this down. Let me circle back to what
7 the environmental agencies have said, and in fact to kind
8 of connect the two as to whether there is a link, possible
9 link or not and I'm going to consider that they might
10 leave before we ask the question while we have them in the
11 room.

12 So I heard Mr. Bishop saying that your open for
13 suggestions that you want to see hard lines and
14 commitments and the rest of all the Commissions. From
15 what you heard from this Panel in terms of attempts to
16 reduce the amount of intake so your 15 billion gallon a
17 day, if there's a target let us say to reduce it to, I
18 don't know, 10 billion by a certain date or something like
19 that (inaudible) come through cooling or any of the
20 (inaudible) that you heard from them, would that be the
21 kind of flexibility that you'd be (inaudible) taken or no?
22 Is, we're talking about I think the (inaudible) or other
23 (inaudible)?

24 MR. BISHOP: You know there's not an easy answer
25 to that question, but I'll give it a shot, which is that

1 our approach will be that you could get there with
2 ultimate technologies as long as you actually meet the
3 target goal reduction. So what we're, what we looked at
4 in the initial, and what we're proposing to put forward is
5 since a track one would be closed cycle wet cooling, which
6 requires some makeup water so you have a certain amount of
7 water that comes in and you have your (inaudible)
8 associated with that. Or under track two it would be 90
9 percent of that.

10 The one area that I would caution folks is that
11 if you're thinking you're going to get to 90 percent by
12 looking back at your initial capacity at the plant when it
13 was built and, you know, at that point you could run this
14 thing, you know, 100 percent of the time, you'd have this
15 huge volume of water coming through, but now you don't run
16 it five percent of the time so you've made 95 percent
17 reduction and so your (inaudible) is not what we're
18 looking at. We're looking at is what were you running the
19 plant at and if you didn't have this controlled technology
20 or this different approach can you reduce it down to
21 within ten percent of what it would be for wet cycled
22 (inaudible). Did I answer your question? (inaudible).

23 MR. MANSOUR: But we're talking about impact.
24 (inaudible) let's just not go through talking about the
25 impact of (inaudible) cooling.

1 MR. BISHOP: Correct.

2 MR. MANSOUR: And what I'm asking is can we
3 target the impact rather than the technologies? So we
4 could say like you heard people say talking about variable
5 speed motors and pumps and it would take the (inaudible)
6 level (inaudible) and all that's all reduction and even
7 the number (inaudible) looks like from what I'm hearing is
8 that that's a very old number not taking into account all
9 the stuff that have changed since then if the industry
10 demonstrates.

11 Again, we're not talking about like in plant
12 lines holistically to reduce the intake, let's just say
13 one example, by so much a certain day, which is
14 (inaudible) so I can (inaudible) responsible. Would that
15 be the kind of flexibility that should be opened?

16 MR. BISHOP: Yes.

17 MR. MANSOUR: Okay. Great. Now I have a second
18 question. Hearing the issues that we in, okay, when
19 owners have tried to solve the OTC issues by making change
20 by which they would have to go through (inaudible) and the
21 (inaudible) kind of say, well this is a different problem.
22 Now you've seen what the (inaudible) between the agencies
23 and (inaudible) resulted in a coordinated effort known as
24 (inaudible) and it pretty much, and with your help as well

25

1 and your acceptance we wish that, you know, something was
2 going to (inaudible).

3 Is there an effort between the (inaudible)
4 agencies between water, state water, regional and air by
5 which the things that you're looking at in (inaudible)
6 climate change of environmental impact holistically so one
7 would know that this is for that purpose (inaudible) say
8 there's some relaxation in my rule to meet this and then
9 it would reverse maybe another attempt from other
10 regulation? Is it, is there a (inaudible) other agencies?

11 MR. BISHOP: There are ongoing efforts on
12 climate change issues on how different regulations
13 (inaudible) climate change. So in general, yes, we are
14 part of that kind of discussion.

15 Meaning specifics, have we met with the air
16 board to say, look, you know, we have these rules going on
17 you have those rules, we need to figure out how to
18 coordinate those only in so far as that we've asked the
19 air board to be part of our working group. We have not
20 gone the next step, which we may have to to say, okay, now
21 we have some sort of a proposed scheduled plan that we're
22 moving forward on we need to coordinate your activities
23 with ours to make that work. I would expect that we will
24 need to do that as we move forward, but it hasn't happened
25 yet.

1 MR. MANSOUR: Can we count on it?

2 MR. BISHOP: Of course.

3 MR. MANSOUR: Now, just before, now (inaudible)
4 back to the Panel, if the Water Board is with their own
5 understanding, and believe me, (inaudible) this issue for
6 like almost two years and I have that knowledge, the
7 flexibility they have demonstrated and the time and
8 understanding to the point where we're really making
9 progress with it. So I know you're really sincere about
10 it and that's over the many months or over the two years
11 (inaudible) great progress and understanding of the issues
12 and being reasonable in terms of you want to move on at
13 the same time you have full understanding what the impact
14 is.

15 Did the rules come out like, we're talking just
16 hypothetically, that is in terms of reduce the impact
17 (inaudible) by certain time rather than the technology per
18 se. Among us, and we're talking about the whole industry,
19 is there a way that the recent community can coordinate
20 that and actually see that that is something reasonable
21 that you can work with?

22 The thing is I'm concerned to understand it when
23 you say every one of us is different? Just say, okay, the
24 other (inaudible) think industry as a whole and we're
25 asking them not to be specific and say this plant by this

1 date, this plant this date, this plant by this date. I
2 want to provide flexibility to deal with the impact as a
3 whole. How can we make that happen? The (inaudible)?
4 Any suggestion?

5 MR. PENDERGRAFT: Well I think that (inaudible)
6 was obviously in the details. I mean we've got, you know,
7 I think there's sort of three groups of units in my mind.
8 There are the nuclear units, which as a consumer and a
9 rate payer I think should be allowed to keep their once
10 re-cooling system in place and we need to figure out a
11 way to do that and mitigate for their impact or, you know,
12 something --

13 MR. MANSOUR: And let us (inaudible) --

14 MR. PENDERGRAFT: -- (inaudible) beyond the
15 (inaudible) --

16 MR. MANSOUR: -- for one.

17 MR. PENDERGRAFT: Okay. As you've seen by the
18 data there's a large group of these facilities that are
19 really only needed for summer peaking. And that's when
20 they run. And their impacts are relatively less
21 significant than some of the other units.

22 And then you've got this select group of plants
23 in local reliability areas that are vintage that are
24 needed year-round. If we're really trying to, you know,
25 consider the marine environment that is the subset of

1 plants that we ought to get transitioned to new
2 technology. And you want those plants that are required
3 year-round to be the plants that don't have once through
4 cooling and that have newer technology.

5 What that will do is push, it will push those
6 plants that continue to operate now around the clock into
7 the group that is only needed during summer reliability.

8 MR. MANSOUR: I guess just what I'm saying is,
9 let us say that the Water Board is (inaudible) for a
10 holistic impact reduction, water intake for example, and
11 knowing that each one is the, and we want to them just to
12 persuade them to stay away from being very specific plant
13 (inaudible) plant of a certain day. How can we coordinate
14 that to the (inaudible) industry so that is achieved? The
15 impact is reduced (inaudible) so we can be (inaudible)
16 rather than leaving it say, you know, it depends on all
17 that stuff, but then at some point in time they have to
18 move forward. Any ideas?

19 MR. HICKOK: Well I think an emphasis on
20 mortality as opposed to say just a body of metric flows is
21 a step in the right direction. You know, the change in
22 volume metric flow you're kind of presupposing the means
23 by which you're going to get the reduction, which is a
24 retrofit with close cycle cooling. So it is (inaudible)
25 producing without reducing the mortality will tell us what

1 that benchmark is and then you can find that there are
2 other technologies that will allow you, give you an
3 equivalent reduction of mortality that may or may not have
4 anything to do with volume. I mean there would be some
5 relationship there. But that's off the top of my --

6 MR. MANSOUR: Any suggestion (inaudible) second?
7 Can you coordinate that? Do you think the industry can
8 coordinate that?

9 MR. ARREDONDO: Can we have coordination, better
10 coordination from the State as well because there have
11 been meetings that have occurred at agency levels where we
12 have been excluded and a good indication of that is that
13 fact that 1978/1980 numbers are still being used by which
14 to measure us. So a greater transparency, greater
15 inclusion by the State agencies as we approach these
16 changes in regulation are required so that we can have
17 that ability to, not only participate but offer, you know,
18 some of the changes that we're making now. But I think
19 that we could probably get to something.

20 MR. BEATTY: You know, adding on to those
21 thoughts is that I think that the generator community is
22 only a part of the puzzle. I think that the agencies have
23 to be involved in creating an environment that allows
24 certain decisions to be made going forward and I also
25 think the utilities have to be part of the solution as

1 well because they're ultimately by and large the ones
2 procuring the energy and providing the (inaudible) which
3 maybe some of this investment can get made. So to say
4 it's just the generator community that has to come
5 together to figure out the problem, I think that's
6 actually just one of the legs of the three-legged stool.

7 MR. VIDAVER: Thank you.

8 COMMISSIONER BYRON: Just if I may, just going
9 off the last comment you just made, do you see procurement
10 as being a key aspect of how we might address this issue
11 as well, Mr. Beatty?

12 MR. BEATTY: I do actually. I think that
13 there's, well I was going to lead into this in one of my
14 later answers, but I think that, you know, there are some
15 scenarios where we could put some investment into these
16 units and maybe actually get them off the river, so to
17 speak, and but part of the solution to that investment is
18 a procurement process and we're not sure right now that
19 the existing procurement vehicles allow us to make that
20 investment.

21 MR. LEUZE: Well we --

22 COMMISSIONER BYRON: Well, yes, go ahead. Go
23 ahead Mr. Leuze.

24 MR. LEUZE: I was just going to, just add a
25 thought that there are (inaudible) tradeoffs that has to

1 be considered here and I think Mr. Mansour pointed out
2 that one trade off is not reliability. That has to be
3 maintained. But then we think about well what level of
4 reduction in impact on marine life is the right target I
5 would ask the question, how is the impact on marine life
6 balanced against the other impacts caused by investment in
7 other resources? For example, if you, and let me just,
8 I'll state it quickly, if you by rough calculation would
9 take about 20 square miles of space to replace our 2,000
10 megawatts of plant with solar thermal or hundreds of wind
11 turbans and the associated impacts of sensitive desert
12 habitat or rafters. I won't go into the numbers. I
13 calculated it based on CEC data.

14 But, and I think Mr. Beatty hit on a key point
15 though, with respect to any investment that we make it
16 will be helpful to have a better basis for projecting what
17 revenues we would be able to earn. For example, a
18 multiyear forward resource adequacy structure would be
19 particularly helpful.

20 MR. VIDAVER: And we'll focus on that in a later
21 question, as you probably know. I just want to get some
22 clarification from Mr. (inaudible). You implied that you
23 can't get a 90 percent reduction in water flow over
24 current levels without going to closed cycle cooling, but

25

1 you implied that you might be able to get to a 90 percent
2 reduction in damage using alternative technologies.

3 MR. HICKOK: Well again, if, you know, we don't
4 know that this concept proves out, but if a deep sea
5 intake accesses a portion of the marine environment where
6 there are relatively few organisms by moving the intake at
7 the plant I might be able to reduce organism mortality 90
8 percent relative to what my current operations are.
9 Better (inaudible) and structure that just dictated a 90
10 percent reduction in the flow that rules out that
11 technology. So again I think it's all about reducing
12 mortality and so that you just need to be careful about
13 the way you draft the regulations.

14 MR. VIDAVER: And the Panelists would agree that
15 90 percent reduction as well is only possible (inaudible)
16 closed cooling. It's just --

17 MR. BEATTY: From our prospective we actually
18 have already seen a 90 percent reduction. But when I hear
19 Mr. Bishop it sounds like none of those efforts will
20 really be considered. I think to get an even more 90
21 percent reduction you're probably looking at tons of
22 cooling air.

23 MR. HICKOK: Yeah. And I'm not aware of any
24 technology that would get you, if the benchmark is 90
25 percent of what you're doing now, well, you know, I've got

1 a plant that runs five days a year, you know, if I got to
2 scale that back ninety percent that's left over.

3 MR. VIDAVER: And (inaudible).

4 MR. PENDERGRAFT: Well and the point I was
5 trying to get to was trying to get is if you are looking
6 at it for industry wide you take the facilities that run
7 the most year-round and you attack those facilities and
8 replace them, which include some of our facilities, and
9 eliminate the once through cooling you've now achieved
10 enough reduction overall to compensate for all the other
11 units that don't run very much. But you can't look at it
12 on a unit-by-unit basis. You need to look at it industry
13 wide, which is I think what you were suggesting.

14 MR. VIDAVER: Attack is an interesting word.
15 Let's turn to closed cooling. In the cases of your
16 individual plants do you see that as, your individual
17 facilities, do you see that as an impossibility or
18 possible? If it's impossible is it due to engineering
19 realities or (inaudible) position for lack of a better
20 word, and if it's technically feasible can you imagine the
21 circumstances under which your costs work out and what
22 obviously you would need some kind of recovery guarantee
23 to lock (inaudible) contract. And is it conceivable if
24 there aren't any engineering constraints and either your

25

1 plant could do that or you can see that as possible and
2 your theoretical sense where some people perhaps?

3 MR. LEUZE: Well, I'll answer briefly. The
4 closed cycle cooling or air cool condenser options we have
5 looked at for both Mandalay and Orman. They are
6 expensive and particularly for the Orman site, which is a
7 relatively small site. It would be, construction would be
8 very difficult. There are also significant impacts in
9 terms of power output capability and efficiency, ten
10 percent or more impact on degrade. No, we're not optimize
11 that, but it's very significant.

12 And, you know, the plain fact is once through
13 cooling is a very efficient cooling system and allows heat
14 rates that approach the emission performance standard for
15 CO2, you know, which is about 9400 Btus per kilowatt hour
16 when using natural gas and (inaudible) our plants are in
17 the neighborhood of (inaudible). So obviously a ten
18 percent increase in heat rate has a GHG implication. So
19 we wouldn't say it's impossible, but it would be
20 expensive, it would be at least in that respect countered
21 to GHG goals and we would require some confidence that
22 we'd be able to recover the cost of that investment.

23 MR. VIDAVER: I would assume you've seen the
24 processing that's done by third parties in this. Do you

25

1 think they're significantly understated in just your
2 plants or do you have any basis for --

3 MR. LEUZE: I think they're understated, but I,
4 you know, we have to refine. Ours is a plus or minus 30
5 percent estimate and --

6 MR. VIDAVER: Thanks. Mr. Beatty.

7 MR. BEATTY: So just to make sure we're
8 answering the same question, the question that was
9 originally positive was do we agree with the staff
10 assessment that's generally kind of infusible to refit
11 with cooling towers and I think this goes back to my
12 initial point, which is I really think you can only look
13 at it on a case by case basis. And I know some of the
14 studies have really looked at it more generally and come
15 to the conclusion that generally speaking cooling towers
16 are not possible.

17 We think that merit that there are some
18 scenarios actually with our Delta units where we could
19 refit them with cooling towers, but, you know, the reality
20 is that the economic viability of this here depends upon
21 the vehicle for recovering the cost of the investment.
22 You know, whether it costs out, which I think is along the
23 lines what you're asking, Dave, was kind of depends upon
24 what you, how you measure it. If you look at it compared

25

1 to a new power plant we think actually it does cost out
2 pretty well.

3 So, you know, I guess the message there is we
4 think that there is a possibility, at least with the merit
5 plants in the Delta region specifically, but in the
6 absence of certainty regarding how those costs are going
7 to be recovered, the investment, is going to be, or then,
8 you know, I think there would be a distinct possibility
9 actually that getting off the river would mean the
10 retiring those units.

11 MR. HICKOK: At Dynegy they're really, there's
12 two plants in play since South Bay, we're planning
13 shutting down in, prior to the (inaudible) schedule.

14 Morro Bay the prohibition at Morro is primarily
15 on the part of the City of Morro Bay, and we've been down
16 the (inaudible) bridge so it's an ancient plant with a
17 relatively inefficient heat rate so when we went through
18 the CEC permitting process to build or replace a combined
19 (inaudible) power plant there, both dry cooling and wet
20 cooling, we were deemed to be infeasible due to city
21 ordinance as for (inaudible) it would be a very big, very
22 loud structure right in the middle of their town and
23 they're very passionate about not seeing that happen.

24 At Moss Landing units one and two went through
25 the CEC licensing process. Part of that was looking at

1 viable cooling technologies. Wet cooling would be
2 infeasible due to a lack of sufficient (inaudible)
3 permits. There's nothing remotely close enough to the
4 (inaudible) need to use that (inaudible) technology.

5 However, I do have enough real estate that dry
6 cooling may be viable. Those (inaudible) cycles are
7 better economic health than my other facilities. It may
8 be technically feasible.

9 The answer somebody would have to give me is
10 whether I'm going to run into issues with the Coastal
11 Commission (inaudible) dry cooling and power (inaudible)
12 sizable individual (inaudible) so I think that's the
13 (inaudible) challenge for units one and two.

14 Units six and seven, we haven't in the past
15 taken a close look at retrofitting those units. I think,
16 you know, my intuition is that they're not feasible just
17 given the possibility of real estate between six and seven
18 and units one and two. There's not a lot of land
19 (inaudible) contributes to those units.

20 They just priced the water flow of the units one
21 and two are so I imagine from an engineering prospective
22 your talking about (inaudible) that are orders a magnitude
23 larger. So we're getting kicked off in the process of
24 doing those engineering studies because we hadn't had the
25 occasion in order to do them in the past. But the jury's

1 out there, but I suspect that unit six and seven in Morro
2 Bay would. We'd most likely retire rather than retrofit.

3 MR. PENDERGRAFT: Yeah, as we see it I don't
4 know if the answer would be the same for all the
5 facilities, but for all our facilities we don't think it
6 makes sense. Even if we were to get guaranteed cost
7 recovery for the investment I think it's not, it's a sub
8 optimal, environmental and economic solution that, you
9 know, the size of the steam turban on a new combined cycle
10 is roughly one-third of the plant's capacity so the closed
11 cycle cooling you need for a new combined cycle is one-
12 third the size. You know, if you put in some sort of
13 newer peaking technologies you even need less cooling
14 capacity, so I think the path to moving to closed cycle
15 cooling in our mind goes through a re-power more than
16 anything else.

17 And I think, one comment I just want to
18 interject as we're sort of determining the fate of once
19 through cooling, we do need to be mindful of the water supply
20 situation in the state and I think the objective to get to
21 some desal plants built and, you know, one can argue, but
22 I think, you know, the desal facilities ideally it would
23 keep a portion of the once through cooling systems in
24 operation to provide the source water and the dilution
25 needed on the brine discharge. And I think a solution

1 that at least that portion of the circulating water system
2 that the desal plant needs for its dilution should be
3 allowed to be used for power generation or you end up in a
4 situation with probably worse environmental impacts.

5 If you dedicate the once through cooling system
6 to the desal facility, but you require the power plant to
7 move to closed cycle cooling you are actually adding
8 incremental environmental impacts that you wouldn't
9 otherwise have if you allowed them to both use the same
10 circulating water system.

11 So I think it's just something we need to be
12 mindful of. I'm sure there, you know, there are people
13 pushing to use alternate technologies for desal as well,
14 but I think we just need to be mindful of the given
15 state's water situation.

16 MR. VIDAVER: We are running out of time and
17 there's one very important question that needs to be
18 asked. Could I move you off of that perhaps?

19 MR. PENDERGRAFT: Fine.

20 MR. VIDAVER: Let's assume that that the process
21 used to eliminate once through cooling and either
22 (inaudible) and replace the (inaudible) facilities or put
23 yourself in the position of greenfield developer we might
24 be looking for another plant to actually compete against
25 ground fill to replace the capacity that would be lost

1 (inaudible) a way from once through cooling. What does
2 that process need to look like from your prospective and I
3 think that the state agencies would say that that process
4 needs to be competitive to provide ground fill and
5 greenfield, (inaudible) equal opportunities to participate
6 and the utility are opposed.

7 Do you have thoughts on the clarity of the
8 (inaudible) the (inaudible) time you would be contract
9 (inaudible) anything else that would allow you to
10 effectively compete in RFOs and commit capital to either
11 re-power your existing facilities or replace them on-site
12 or investing in greenfield?

13 Was there a question in there? I don't know
14 (inaudible) --

15 MR. LEUZE: I guess the preliminary question
16 would be how you balance a transmission investment against
17 generation investment in the first place and then how
18 granularly do you define the requirement for generation
19 procurement. The ISO did a study it published last
20 November, it was rather frightening in it's implications.
21 It only looked at transmission investment, but it was
22 enormous requirements and consequences and so somehow it
23 would seem useful to have a framework for how generation
24 and transmission investments are, the tradeoff between
25 those is made.

1 But obviously clarity, a consistent process, a
2 transparent (inaudible) and a multiyear for research
3 adequacy framework is a good place to start.

4 MR. BEATTY: Yeah, I'm not sure if I'm answering
5 your question, but I'll through out these thoughts is, you
6 know, I think in our sites our units, and particularly the
7 Delta units that they're actually a very inexpensive
8 source of capacity for the state.

9 Kind of an analogy I was working on, and it was
10 alluded to earlier, is the idea of, you know, the 25-year-
11 old car. You put some investment into it, you sell the
12 245-year-old car. But what I would say is for these units
13 really the kind of car we need is one that you maybe drive
14 to the market once a week and maybe even less than that.
15 And so how much money do you want to spend to come up with
16 the kind of car you need to drive to the store once a
17 week. And the analogy I would make is you can buy a new
18 power plant to cover that capacity or you could put some
19 money into these existing units and have a fairly cheap
20 source of capacity.

21 I think the existing RFO process slants toward
22 the idea of new units. The existing RFO process, as we
23 see it at least, is not really an environment where the
24 refitting of our units is really being taking seriously
25 and I think that if we could create that environment we

1 think we have something to offer the State in terms of
2 cheap capacity. If the State, or if the procurers of
3 electricity aren't interested in that for whatever reason,
4 it's the nature of the characteristic of the plant or
5 whatever it is, then so be it. But if you want a fairly
6 reliable capacity from these plants we think it's a
7 relatively minor amount of investment could provide that
8 solution.

9 MR. VIDAVER: In the form of (inaudible)?

10 MR. BEATTY: In the form of refit.

11 MR. HICKOK: Well I think refitting is a good
12 option for units that are near done in their economic
13 lives, but there are a lot of reasons why I think that at
14 any of these plants you can deliver a re-powered facility
15 with alternative technologies and relatively cheap because
16 you already have so much infrastructure there. In Moss
17 Landing's case I even have an turban building, you know,
18 and just to back him up and (inaudible).

19 I think my concerns with the procurement
20 processes is, you know, I feel I can compete if it's truly
21 level playing field, but then this isn't truly level, you
22 know. Don't make me sign a ten-year supply contract and
23 compete with a transmission project that has 30 years
24 (inaudible). They're both long-term investments for a
25 merchant plant generator to finance it. If you give me a

1 ten year contract I've got to load so much of my value
2 into that ten years to get it back that by the time you're
3 done it looks like it's an enormously more expensive
4 option.

5 If you give me the same 30 years to (inaudible)
6 on (inaudible) or even 20 years I can bring my cost down
7 to something that's a lot more of an apples to apples
8 comparison. And then, you know, I would also ask that the
9 analysis been truly comprehensive.

10 You know, transmission might be a good way to
11 get local reliability concerns met, but it's not
12 necessarily a way to get supply adequacy. And a lot of
13 this issue is not just local reliability concerns, but
14 whether you have enough megawatts.

15 And a transmission line is great, but if you
16 have a transmission line with no generation at the end
17 you've really bought nothing and I've got assets in the
18 west, I'm not sure where the surplus generation is that
19 you're tapping into in the transmission line so, you know,
20 I would probably spend a lot of time focused on making
21 sure that the evaluation criteria was an equitable one.

22 MR. PENDERGRAFT: I don't know if I have a whole
23 lot more to add except it's a little bit unclear to me the
24 way the RFOs are (inaudible), right. There's also RFOs

25

1 and there's new source RFOs and how does a unit
2 replacement or re-power fit into either one of those?

3 And this, I'm not talking about where we, okay,
4 we shut down a unit today and five years from now we're
5 building a new one, but we want to bid a project that is,
6 you know, constructing a new plant while we're operating
7 the existing plant and then, you know, on the commercial
8 date we flip the switch and we move from the new one to
9 the old one and how do the IOUs look at that.

10 It's not necessarily incremental additional
11 capacity it's, you know, it's taking some capacity out and
12 replacing it with different capacity. And if that gets
13 any sort of different treatment, you know, any RFO does
14 that, does the number of megawatts that are being procured
15 in that manner, should that influence the amount of
16 megawatts the IOU is allowed to procure or look for,
17 because they're clearly different products. The new
18 (inaudible) greenfield versus a replacement and whether
19 the RFO process should be somewhat adaptive and depending
20 on how much brownfield projects are being selected by the
21 IOU it would sort of differentiate how much they're
22 allowed to procure for.

23 So that's something I'm still a little unclear
24 on how that would work or how that does work in an RFO
25 process the way they've got them segregated.

1 MR. ARREDONDO: Just to add again to what's
2 already been said and then try not to make it too lengthy,
3 but just an observation that in the current RFO process
4 the local generations may be significantly under valued.
5 So in the existing market structure I guess adding
6 transparency for what that value might be would be
7 important. The risk would be more at the PUC level an
8 (inaudible) function procurement process.

9 Also back in 2004, so jumping in our time
10 traveling machine, I was before this Commission and argued
11 for the fully burdened delivered below cost understanding
12 of what generation might cost because at the time we were
13 arguing over generation and it might be in other states
14 that we'd be able to bring in through transmission, and
15 obviously we know what it takes to build transmission in
16 California. It takes a lot of time and a lot of money.

17 And then I'm trying to understand where that
18 generation was actually going to come from. And then
19 doing an apples to apples comparison versus the
20 (inaudible) brownfield that could be re-powered and could
21 alleviate the greenhouse gas issues, OPC issues and adding
22 flexibility to our RPS goals when you compare those on an
23 apples to apples basis, what would be better for us?
24 Would it not be to re-power at existing sites?

25

1 Now we face the local burdens of, you know,
2 please don't do this in my backyard again and where local
3 communities might say, gee now that you're off the once
4 through cooling you should move.

5 Well we're still very infrastructure dependent.
6 Natural gas is there, transmission is there, so the cost
7 again, the fully burden delivered to customer cost is
8 significantly less by doing these re-powers at the
9 existing sites. Not to mention all of the attributes to
10 grid reliability that Mr. Mansour has to worry about.

11 MR. VIDAVER: Are there any questions from the
12 (inaudible)?

13 COMMISSIONER BYRON: Did you, what I was going
14 to suggest, go ahead for another five minutes or so if
15 you've got, did you get through your last question on
16 here?

17 MR. VIDAVER: Well the final question relates
18 to narrowly targeted RFOs and ensuring that market power
19 can't be exercised. That would really require you to put
20 on (inaudible) developer hat because the (inaudible) your
21 current position. There's one question that was on this
22 list that we didn't deal with directly was whether or not
23 units at their existing facilities could be sort of
24 treated separately and handled differently? Mr. Hickok

25

1 could probably (inaudible) with respect from Moss Landing.
2 This is going to be pretty easy to do.

3 MR. BEATTY: Actually that questions a germane
4 (inaudible) it went on earlier today between Mr. Mansour
5 and Mr. Strauss from the PUC. I think there was a bit of
6 confusion about the status of the Portrero unit and I
7 thought I would just address that briefly. Maybe someone
8 has a (inaudible) but brief nonetheless.

9 As to Portrero unit three we certainly see them
10 as having, or seeing that unit having distinct (inaudible)
11 from our Delta units.

12 The Trans Bay Cable is being constructed. It's
13 currently targeted to be energized sometime in 2010 from
14 what I understand, in the first half 2010 and that once
15 it's energized and in service that the need for unit three
16 would disappear and at that point the R&R contract would
17 or, you know, sometime shortly thereafter the R&R contract
18 would probably lapse and as a result of that the unit
19 three would be off line. So really in our future planning
20 we don't see unit three operating past 2010.

21 And then in terms of the Delta units, I've
22 already talked about kind of some of the visions we could
23 see for those units and maybe one other distinguishing
24 factor there is in Pittsburg we actually already have
25 cooling towers in place. They're serving the Pittsburg

1 unit seven and there is a scenario where perhaps those
2 cooling towers are shifted over to units five and six,
3 which tend to be more viable units than Pitt units, so
4 it's a scenario, it's something that distinguishes even
5 within the Delta units the Pittsburg plant from the Contra
6 Costa plants.

7 MR. VIDAVER: Two people that, we have --

8 MR. PENDERGRAFT: Can more of us answer that
9 question or --

10 MR. VIDAVER: Oh, go right ahead. Yes.

11 MR. PENDERGRAFT: Actually, I mean, I think most
12 all of here are trying to, as Mansour and the gentleman
13 from the ISO said, balance a lot of competing priorities
14 here.

15 Really we're just trying to look for, in our
16 view, a solution that sort of balances reliability,
17 economics, you know, the environmental air and water and
18 then what's feasible. But I think by looking at it that
19 way you converge on unique treatment for different units
20 at a similar site. And that's exactly how we would view
21 it, that we see sort of an ideal solution being one in
22 which a subset of our units are re-powered and replaced
23 with new technology. They provide the bulk of the year-
24 round local reliability services that are necessary.
25 There's a smaller subset of existing plants that are

1 allowed to continue operating with once through cooling in
2 place. They're only serving a very unique need in the
3 summer. Their impacts are relatively small because of how
4 infrequently they operate.

5 And we think that's consistent with at least the
6 direction the Supreme Court was going in by using the cost
7 benefit and the original federal rule that actually
8 exempted units with capacity factors under 15 percent from
9 the entrainment standard.

10 Now we would be willing and open to consider
11 mitigating for any remaining impacts that we had on those
12 units that were serving a very unique need during the
13 summer.

14 And then there would be a, you know, a further
15 subset of units that would be retired due to the re-
16 powering of the technology that runs, or the units that
17 run the bulk of the time.

18 And to us that is a solution that we think
19 basically achieves the best overall balance between when
20 you're looking at rate pay or impacts, the actual marine
21 environmental impacts, air and grid reliability.

22 So we definitely see different treatment for
23 different units at our three different sites. And that
24 would be a sort of an ideal solution for us.

25

1 MR. VIDAVER: So are you talking about
2 (inaudible) morality that is not touched at all, but
3 Redondo Beach is? Are you talking about getting rid of
4 once through cooling in Alamitos three and leaving it in
5 place at Redondo Beach because it never runs? Are you
6 talking about 90 percent across your portfolio in the LA
7 basin? Ninety percent reduction in either flow or
8 (inaudible)

9 MR. PENDERGRAFT: And I am not saying that we
10 would achieve a [sic] overall 90 percent reduction as
11 defined previously. And I'm trying to keep minds open
12 that maybe if you factor in a thorough economic analysis
13 of that environmental policy that maybe we should make
14 some tradeoffs.

15 And the economic analysis I haven't see is the
16 cost of replacing all of this capacity with new stuff.
17 It's buying new cars for all this stuff, we could have
18 cars that are already paid for and sit in the garage most
19 of the time. Can we afford that?

20 MR. VIDAVER: I think you have the last word.

21 COMMISSIONER BYRON: Gentlemen, thank you very
22 much. Very helpful and a wealth of information. I
23 learned a lot of new things here. I think there are
24 things that we're going to look at even in addition to
25 everything else that we're looking currently in working

1 (inaudible) and in particular, you know, giving credit for
2 early action emphasis on mortality over volume metric
3 issues. I think all very good. And this will be a very
4 transparent process.

5 You will see that the State Resources Control
6 Board will take this on. The State Water Resource Control
7 Board will take this on in a very transparent way. We
8 welcome your continuing involvement and thank you for
9 being here today. We'll go to the next Panel.

10 MS. KOROSSEC: Yeah. The next Panel will be our
11 utility Panel. This is already (inaudible) again.

12 MR. MINICK: And I think, while we're setting
13 up, let me just add a few other things. I know Mr.
14 Mansour would like to have some more opportunity for
15 question and interaction, so we'll try and factor that in,
16 here in these last few panels, if not at the end. The
17 concern is at the end that we may be losing a lot of you.
18 And I think I'd say these remarks to both this last panel
19 and the one that's coming up. You know, we're acutely
20 aware of the fact that this all has to be done in terms of
21 the economic interests of the owners and operators of
22 these plants. And that's an important consideration in
23 any rule that's promulgated. We're hoping to do one
24 that's primarily on the basis of reliability. But, I
25 think, as you heard earlier, economic considerations will

1 certainly be considered in all of this. And I certainly
2 got that message, as well, from the last panel. There
3 needs to be a willingness to help resolve these issues as
4 it serves your financial interests as well. So, Dr.
5 Jaske, welcome back.

6 DR. JASKE: Thank you. So this afternoon we
7 have representatives of four utilities. Mr. Minick with
8 Edison, over here, and his colleague, Mr. Savage, and then
9 Mr. Krausse and Mr. Hatton, with PG&E, Rob Anderson with
10 San Diego, and Mr. Tharp with LADWP. Interesting they're
11 all sitting (inaudible).

12 MR. MINICK: Good.

13 DR. JASKE: That's good. Let's focus the first
14 question on these questions that were raised in the last
15 panel on longer run procurement. Particularly procurement
16 that encourages new infrastructure, whether it's new new
17 capacity or replacement capacity. Generally speaking,
18 what options exist to more tightly focus your RFOs to
19 bring forward replacement capacity?

20 MR. SAVAGE: Thank you, Gordon Savage. Well, we
21 believe in a market based transition as opposed to command
22 and control. And so what we'd like to do in that is
23 recognize the costs of the system and also look at the
24 challenges that, in terms of matching the most plants to
25 the system needs. In our LTPP, as mentioned earlier, we

1 do have two types of RFOs. The new generation RFO and an
2 all-source. The prices for the capacity in the new
3 generation tend to be much higher than the existing
4 generation. And the point of the new generation RFOs is
5 to consent that those new plants to be built. And, in
6 fact, it controls the cost of the all-source article by
7 having sufficient capacity from the system. So what we'd
8 envisioned is RFOs targeted to new generation which we
9 currently have. I want to point out our old RFO that was
10 started in 2006, took just two and a half years to
11 complete in total, we had three phases to it. And the
12 world has moved on significantly from that point. So we'd
13 be looking at targeting changing the specifics of the RFO
14 to match the needs of the system. It wouldn't be simple.
15 I mean, the timing of the article will be difficult.
16 You've got, we'd want to have competitions and a broad
17 field, so you look at that and you look at specifically
18 replacing brownfield plants. We do have in our LTPP a
19 preference to brownfield plants and plants, and repower,
20 and most tend to be once through cooling plants. And
21 also, this issue is far too (inaudible) with (inaudible),
22 given prior reserve issue and current permitting problems.

23 COMMISSIONER BYRON: Dr. Jaske, are we going to
24 hear from every panel member, because I'm just thinking if
25 we, okay, so that's the SCE response on that one?

1 DR. JASKE: Yes.

2 COMMISSIONER BYRON: Thank you.

3 MR. KRAUSSE: We split them up by numbers so
4 you're kind of confused as this is basically the
5 procurement question, right?

6 (inaudible)

7 MR. HATTON: Would you repeat the question,
8 please, thank you.

9 DR. JASKE: So it's really a narrowing of the
10 first question right down to the issues that the last
11 panel raised about how to modify either the new gen RFOs
12 or the (inaudible) source of the (inaudible) of those.

13 MR. HATTON: Currently, the longterm RFO process
14 considers offers to develop new facilities, and this
15 process has historically been structured so that offers
16 for facilities using the once through cooling units are
17 not eligible to participate. That's narrowing down that
18 scope. PG&E conducts its longterm RFO process currently
19 consistent with CPUC rulings and policies that are in
20 current operation. As part of the current longterm RFO,
21 PG&E's lead was based upon the 2006 longterm procurement
22 title. And in this current longterm RFO, PG&E has stated
23 its preference to obtain generation from new dispatchable,
24 operationally flexible resources. The bottom line dates
25 no later than May 2015. By obtaining such resources,

1 particularly within the Greater Bay Area, PG&E then can
2 reduce the need for once through cooling units.

3 DR. JASKE: Rob?

4 MR. ANDERSON: Rob Anderson, San Diego. And, I
5 think maybe it'll help to kind of put in perspective where
6 San Diego is right now. There were only two once through
7 cooling plants down in San Diego, South Bay and Encina.
8 South Bay, everyone is anticipating will be retired
9 shortly, within the next year or two, hopefully no later
10 than summer (inaudible). So that plant will pretty much
11 take care of itself. The Encina power plant, the NRG that
12 owns that right now, is already going through the CEC
13 licensing. They had proposed to do a repower, a new
14 plant, next to it, at which point they would actually shut
15 down three of the five units at that plant. And so, in a
16 lot of ways, there's the once through cooling issue in San
17 Diego is almost taking care of itself, although I wouldn't
18 say there wasn't some planning and work to make all this
19 happen.

20 So we may be really down to dealing with two
21 units in San Diego, and what happens to those two units.
22 We have historically, and we will continue, when we've
23 gone out with RFOs, asking for new generation, we've been
24 willing to do longterm contracts, 20, 25 year contracts.
25 There are some concerned owner groups of generators, that

1 they were concerned with 10 year contracts forcing their
2 prices up. We've been willing to do the longer term
3 contracts to help get that price down for our customers.
4 And so, I'm not sure that there's a lot we really need to
5 change going forward.

6 Our next RFO, we will ask for additional new
7 generation. That may be enough to allow Encina to shut
8 down units four and five. I'm a little hesitant to go out
9 and ask for a product which is a repowering of a once
10 through cooling unit because there is only one party that
11 can get that. And I'm not really sure I've got an all
12 source RFO if there can only be one bidder.

13 DR. JASKE: Mr. Tharp, is LA in the position of
14 procuring resources from, you know, outside its own fleet,
15 or is your activity almost, essentially restricted to the
16 issue of the operation of your own resources?

17 MR. THARP: Well, we are currently in the
18 process of acquiring numerous renewable projects and most
19 of those are outside of our service territory and will
20 require transmission. I feel like in some ways I should
21 have been on the previous panel. We do own and operate
22 three facilities with once through cooling that have 2700
23 megawatts of total capacity, which is about 45% of our
24 peak generating capacity. Our Harbor plant has eight
25 units, with only one using once through cooling. Haines

1 has seven units, five using once through cooling. And
2 Scattergood has three units, with three using once through
3 cooling. Since the 1990s we've gone from 18 units down to
4 nine, so we've cut roughly in half the number of units
5 using once through cooling in our fleet. The question
6 talks about, you know, what kind of options we see, and,
7 obviously, you could shut it down, you could repower it,
8 or you could do some kind of retrofit. Our experience is
9 a strong preference for repowering. We need this power in
10 these locations in our system to support the Port, to
11 support the Airport, to support the West Side of the city,
12 to support the refineries that are in the southern part of
13 our system. These are the only stations that we have that
14 are in these geographical locations, so they're very
15 important to us and we would like to maintain these sites
16 for generation into the future.

17 DR. JASKE: So do I understand you to be saying
18 that there, there -- although you may not use this
19 terminology, these are essentially local reliability needs
20 for some, if not all, of that capacity?

21 MR. THARP: That's correct.

22 DR. JASKE: Thank you. So, let's try to move on
23 to question number 2, come back to you, Mr. Savage. So I
24 know that in the '06 LTPP proceeding with the decision in
25 December '07, that gave allowance for some degree of

1 retirement of ageing plants. Is there actual pursuit of
2 OTC mitigation in the (inaudible) Code of (inaudible)
3 Processes that has been conducted to this point?

4 MR. SAVAGE: In the current LTPP, no, there is
5 no specific OTC procurement. The only thing that I did
6 mention before was the preference towards the new
7 generation of brownfields and repowers. Yes, it's the
8 quality of the factor in evaluating new generations.

9 DR. JASKE: PG&E?

10 MR. HATTON: As I discussed earlier, there's no
11 specific requirement as far as the OTC. Our longterm
12 request for offers are, have been targeted towards new
13 facilities. The process, again, is trying to meet need
14 determination as part of a longterm planning process, and
15 currently our last RFO, or current RFO, is based upon that
16 which is part of the 2006 longterm procurement plan. As
17 part of this process, PG&E has stated that it would like
18 to have new dispatchable operational flexible resources.
19 These are the types of resources which currently provide
20 (inaudible) services that one that are currently used
21 currently produce. We're looking for these, you know,
22 with online dates no later than May 2015, and the hope is
23 that by obtaining new resources that can do many of the
24 same tasks that once through cooling units can do, that,
25 particularly through the Greater Bay Area, PG&E could

1 reduce the need for these once through cooling units.

2 DR. JASKE: And just in a follow up, when we're
3 talking about Greater Bay Area plants, we're talking about
4 the Pittsburg and Contra Costa plants.

5 MR. HATTON: Primarily, yes, sort of the
6 geographic area of the Greater Bay Area. The local
7 capacity wide (inaudible) area.

8 DR. JASKE: Is there anything more you want to
9 add on behalf of San Diego, for this second question?

10 MR. ANDERSON: Probably not a lot other than I'm
11 not sure modify is a good word. I mean, we've been kind
12 of looking at this issue, we knew these plants are getting
13 older. There's kind of been a desire for the city to get
14 (inaudible) shut down. So, I mean, our procurement over
15 the last, probably four or five years, our efforts to get
16 the Sunrise Power (inaudible) has all been driven with a
17 recognition that these older plants have a minimum number
18 of years left on them. So when you say that the once
19 through cooling issue we knew would be (inaudible) factor,
20 it might be great to say that given some (inaudible)
21 panel. But we recognize these are older plants, their
22 life is coming to an end. We need to find a way to get
23 our grid up and running, given those plants will retire
24 sometime.

25 DR. JASKE: I think maybe question 3 would be

1 helpful here. Although we haven't been very specific, you
2 know, as in my opening presentation this morning, you
3 know, sort of outlined (inaudible) South Bay as an example
4 where there's pretty well understood timeframe in which
5 that plant might no longer be necessary. You know, were
6 there to be more generally, you know, that kind of
7 understanding about the existing (inaudible) in our
8 various service areas. I urge you to take advantage of
9 that knowledge and, you know, and sort of contracting with
10 plants, you know, up to that point and not contracting
11 with them, you know, beyond that point, and, you know, in
12 effect use the procurement process to help cement that
13 plan into reality.

14 MR. SAVAGE: Just to clarify, are you saying
15 that there would be a plan for the plant shutting down on
16 a date certain and therefore we wouldn't contract with
17 that plant further on?

18 DR. JASKE: Let's just say, in a hypothetical
19 way, yes.

20 MR. SAVAGE: Yeah, well, we wouldn't want to
21 contract at the point where they're (inaudible) retiring
22 their plant. But it's clear our LTPP sets out our
23 timeline under the contract (inaudible) it's currently 59
24 months and it has to start within 12 months, that
25 contract. And so that puts a time limit on how far out we

1 can contract. And part of our due diligence, if they came
2 and told us that they had retirement plans, that would
3 come up in the negotiations to the contract.

4 MR. HATTON: I guess similar to what Edison has
5 said, you know, the possibility exists that we could
6 target, or we could have contracts with a plant as
7 (inaudible) also stated that our current longterm planning
8 procurement allows for sort of one to five year contracts.
9 PG&E currently believes that existing OTC facilities are
10 eligible to participate in this intermediate term or
11 (inaudible) process, that's what PG&E calls it, and for
12 the 2009 cycle, for example, PG&E's procuring for power
13 out through the 2013, to the extent that any plant would
14 fall into that particular timeframe. Of course that would
15 be eligible to participate as policies and regulations
16 change, PG&E could be prepared to make changes in its
17 (inaudible) intermediate (inaudible) process, for example,
18 to the extend the years or (inaudible).

19 MR. ANDERSON: I want to turn this question
20 around a little bit, given that San Diego's a pretty
21 constrained service area. And to some extent, until new
22 generation is built (inaudible) gets built, basically
23 where in the current situation where everyone's through
24 cooling plant is needed for everyone to meet their local
25 RA obligations. So really, it isn't that I need to know

1 so much about the once through cooling regulation, but,
2 for the most part, these plants are going to have to be
3 relied upon (inaudible). I think even if we launched an
4 RFO today, we're probably talking about 14 or 15 before
5 that (inaudible) plant would ever get built. So I think
6 we're going to be relying on some of these units out to
7 that timeframe for reliability reasons, much less for the
8 regulations. I'm not sure the regulations will really
9 drive us to need to change anything near term.

10 DR. JASKE: Okay. That actually is a --

11 MR. MANSOUR: Mr. Jaske, if I can just, if I can
12 just make sure that some points are very clear to all of
13 us. At least the heat waves of both 2006 and 2007, every
14 single generator was online and every single generator was
15 needed, plus all the (inaudible) were loaded. That's a
16 fact. Now is there any debate that every single generator
17 in the system today is needed from a consistent capacity
18 point of view.

19 DR. JASKE: You can correct me (inaudible) I
20 don't think all generators have contracts with us for
21 resource adequacy purposes. So --

22 MR. MANSOUR: (inaudible) needed.

23 MR. MINICK: Well, a lot has changed since 2006
24 and 2007. Our loads have dropped significantly and we
25 have a lot more load management and energy efficiency

1 programs in place. So I can't say with certainty that I
2 absolutely have to have all plants right now. Certainly,
3 I needed them then.

4 MR. MANSOUR: So, we can then, what? Like we
5 don't need?

6 MR. MINICK: Hypothetically, maybe a 1000
7 megawatts or something, we haven't, I haven't gone back
8 and looked at the exact numbers. But if I took a look at
9 the summer right now, I think the ISO has, it's one of the
10 better summers for us in the last (inaudible).

11 MR. MANSOUR: Oh, because of the recession,
12 because of the recession.

13 MR. MINICK: Yeah, right (inaudible).

14 MR. MANSOUR: (inaudible) system forever, that
15 would be fine.

16 MR. MINICK: But, the question was do I need
17 them right now, and things change in the future. I am a
18 planner, for a long, long time at Edison. Things are
19 going to change over the future, we are pushing energy
20 efficiency. We are pushing demand side programs. We are
21 pushing the renewables. And so, in time, based on pure
22 capacity, there might be a reason not to need all these
23 plants. But I have to look behind the grid, that's your
24 main responsibility, and I'm very concerned about that in
25 some regards. We have to have the ability to integrate

1 new renewables and we have to have the ability to keep the
2 voltage up and use inertia and all kinds of operating
3 criteria. And that's where it gets a little more tricky,
4 okay. A lot of these plants provide services because our
5 system was built from the fifties on around a grid that's
6 basically local right now. And to try to import all the
7 power we need to run the grid is a daunting task. If your
8 engineers looked at it, that's a five billion dollar
9 expenditure and I don't think they solved all the issues.
10 They did see that for five billion they could try to
11 import power. I'm not sure they solved all the inertia
12 issues and some other issues under all operating
13 conditions. I think they sort of said we got more work to
14 do.

15 MR. MANSOUR: Yeah, I just want to add that
16 (inaudible) we are actually in peak times, we still get
17 20-25% from out of state, which is a quantity that I don't
18 know whether we can depend on it with any reality. Then
19 your 1000 megawatts, I don't know if we can just
20 (inaudible) 1000 megawatt, knowing that someone else,
21 somewhere else will build it for us and we'll always be
22 able to get it. The second question is on integration on
23 renewables. At least all (inaudible) at our lab, I don't
24 know if anyone has done a study to contradict that, the
25 capability of the current fleet for regulation, for

1 reserve, for everything, is needed to support those 20%,
2 at least, if not more, much more, at 33%. Now that is not
3 a service that necessarily you utilities can contract for,
4 right? So what do you suggest? Who is to actually make
5 sure to keep those facilities in service to provide those
6 services that you do not contract for, but it is needed
7 for the system?

8 MR. MINICK: I think we would be responsible for
9 our ancillary services for our load. At least, I'm not an
10 (inaudible) expert, but I think that's our obligation.
11 Regarding studies of the future, I know your people and I
12 are going to start working on a 33% renewable integration
13 analysis and I've read your old analysis. I know it
14 pretty well. I can't say with the way things change in
15 the future, the future's going to be radically different.
16 We're going to have electric vehicles, we're going to have
17 more solar cells on roofs, we're going to have changes in
18 the way the grid is built out. Then I will definitely
19 need all those resources in the future. I think it's a
20 reasonable assumption for the time being because of the
21 intermittency of some future plants and resources, like
22 wind. Wind is a little scary when it doesn't show up at
23 the time of the peak and things like that. I can't say
24 with certainty I will always need this level of these
25 kinds of resources. We have done some studies. We have

1 looked at new technology and how we've built out the grid.
2 We do like Elements 100 technology for peakers. We have
3 contracts with some, or even signed the contracts. We
4 can't build them because of the (inaudible) issues right
5 now. So if we could have more peakers on our system, if
6 we could have more hydro pump loads, or more compressed
7 air energy storage, or more batteries, there may be a way
8 to build the grid differently than we have it right now.
9 Again, I'm not saying you shouldn't have them for the time
10 being. The future is very difficult to predict and very
11 difficult to plan for.

12 MR. MANSOUR: So what do you suggest Mr. Bishop?
13 Say you're going to need 2000 megawatts, you going to shut
14 them down, or what do you suggest for him? Because I'm
15 talking to them talking to you, I'm suggesting to you.
16 What do you suggest then? Like we don't need it all,
17 take, you know, some amount of it?

18 MR. SAVAGE: I'd go back to the previous panel,
19 I think they mentioned about looking rationally at the
20 overall system. Like let's look at the total cost, the
21 total environmental benefits, both air and water, and make
22 sure we're doing the best things for society as a whole.
23 I mean, looking at, specifically just the water impacts,
24 the ocean impacts (inaudible) is starting the impact on
25 air and land use. I think we get to a suboptimal

1 solution.

2 DR. JASKE: Let's try converting Mr. Mansour's
3 question into a very specific one. The ISO's current
4 studies for PG&E say the Greater Bay Area has a surplus.
5 ND26 overall has a surplus, will have a surplus for at
6 least a number of years. Gateway just came online, it's
7 essentially next door to Contra Costa. Does that mean
8 that one of the Contra Costa units essentially could be
9 shut down tomorrow, barring any, you know, contract that
10 exists? Because it's really not "needed" for reliability
11 and achieve some environmental benefit.

12 MR. HATTON: Well, I guess there's, in my mind
13 there's two types of reliability. There is system
14 reliability and then there might be local reliability or
15 reliability for specific ancillary services. I think with
16 me, and what you've talked about, as far as looking at the
17 Greater Bay Area, or the ND15 or ZP26, is primarily
18 looking, or counting megawatts, versus really system
19 reliability (inaudible). If one dives down and looks at
20 specifically a local capacity constraint, I think there's
21 some studies that we've done that say no, there are not an
22 excess of potential resources. And I think we'll be
23 getting to a question later, which I can address some of a
24 specific study when we talk about the transmission system
25 improvements that might allow existing facilities to be

1 retired.

2 DR. JASKE: Okay. Maybe before we leave this
3 set of questions and move on, Mr. Tharp, or for LADWP,
4 would you, you made a point that the plants that LADWP
5 presently has, in the Harbor and Scattergood areas, you
6 know, are needed. Is all the existing level of capacity
7 that's at those general facilities needed? Or is it that
8 some capacity is needed at those three locations?

9 MR. THARP: Oh, I think some capacity is needed
10 in all those locations. Some of the slides that
11 Mr. Vidaver showed indicated at least two of those plants
12 had units running 365 days a year. And so, I mean, we
13 need generation in those locations. The type of
14 generation, and what it uses for cooling, may change, but
15 we need generation in those locations.

16 DR. JASKE: And are there contingencies that LA
17 is guarding against that are, you know, observable in, you
18 know, the particular snapshot year of operating history
19 that he was showing would imply a value for that capacity
20 that sort of goes beyond 2008 or 2007 operating history
21 that he was showing?

22 MR. SAVAGE: Well, I think to kind of use one of
23 the things that Mr. Mansour said, during the summers in
24 '06, '07 and '08, there were weeks and months where every
25 unit was on in all of our system.

1 DR. JASKE: Let's turn to question 4 and this,
2 of course, utilities (inaudible) table, do still own some
3 facilities, so for those that you own and operate, what is
4 your commitment or your planning for reducing or
5 eliminating OTC?

6 MR. SAVAGE: We're down to one plant, which is
7 SONGS, and we've done a number of technical upgrades to
8 reduce the environmental damage from that plant. As well
9 as three environment projects to help offset the effects
10 of the plant, including wetlands, 150 acres wetlands
11 planned near Carlsbad, five million dollars towards Hubs
12 White Sea Bass Hatchery, which (inaudible) shut down plant
13 now from time to time to save those fish, and the Mueller
14 North Reef project, which is an artificial giant kelp
15 (inaudible) note the California CPC, in its decision,
16 fully believes that these projects, along with the
17 technical upgrades, fully offset the all marine impacts
18 from SONGS.

19 DR. JASKE: So do you see (inaudible) made that
20 decision?

21 MR. SAVAGE: Yes, it's the Coastal Commission.

22 MR. MINICK: Oh, it was the Coastal Commission,
23 I'm sorry. Do you have the citation?

24 MR. SAVAGE: No, but I can Google and get it for
25 you.

1 MR. MINICK: Just, in your written comments, if
2 you'd please provide a citation.

3 MR. KRAUSSE: Dr. Jaske, Mark Krausse, PG&E, I
4 just quickly want to say how much we appreciate that the
5 agencies are lending your expertise (inaudible) to our
6 Board. As I think has been mentioned mostly today these
7 points were all covered, that we've retired Humboldt, or
8 will be by the time 2010, we expect to see once through
9 cooling eliminated there. The decision to dry cool the
10 (inaudible) Generating Station. The retirement of Hunters
11 Point and finally, most recently, Colusa (inaudible) dry
12 cooled project, approved by the Commission. PG&E will,
13 like Edison, have just one once through cooled project by
14 the end of 2010, that is the nuclear plant. I think
15 that's the, I'm glad that we've gotten to that because,
16 you know, this is the parenthetical of this whole OTC
17 discussion is what do we do about the nuclear plants.
18 Just going into the impact issue, Diablo Canyon was built
19 and designed to avoid any (inaudible). The cove, the way
20 that it's built, is onshore (inaudible) offshore, has as
21 the Central Coast Water Quality Board says, virtually no
22 impingement, and the entrainment, we, through studies that
23 the plant has done since before construction. We started
24 studying, it's the largest database of biological studies
25 that we are aware of, certainly on the west coast, we show

1 about a 10% entrainment of (inaudible) those rocky reef
2 species, but no demonstration of adult population impacts.
3 And I believe even the Water Board's expert panel
4 essentially came to that same point of view. That we know
5 that are eggs and larva being entrained. And I raise this
6 not to, I know we've been admonished not to talk about
7 (inaudible) policy, it's really to put it in the context
8 of, if you juxtapose the impact on (inaudible) in a moment
9 here, California's environment, its air quality, its goal
10 of meeting EB32 mandate. If you juxtapose (inaudible)
11 impact, I think that's where we (inaudible). So PG&E has
12 evaluated all current screening technologies for many
13 years and most recently it has been suggested by Water
14 Board staff and others, a cylindrical wedge water screen.
15 So that's something we looked at very seriously, but given
16 the Central Coast climate and kelp and other things that
17 already take occasionally a (inaudible) trip, that would
18 be infeasible. We've done extensive study of retrofit at
19 Diablo Canyon and we hope to share before the next
20 workshop with all the energy agencies (inaudible) that
21 shows substantial environmental impact from retrofit. And
22 I guess that's where, you know, the previous panel on
23 permitting wanted to hear a little more meaningful
24 discussion about permitting retrofit. But of course with
25 the gas plants, the issue is repower. I would have loved

1 to have heard, and I'm sorry, I would have (inaudible)
2 question period, whether the Coastal Commission would
3 permit, I believe we talked about 120 60x60x60 foot
4 cooling towers that would take a huge footprint out of
5 Diablo Canyon to mitigate those other impacts, enormous
6 excavation of over two million cubic yards of the adjacent
7 (inaudible) hills. It was found by both the Ocean
8 Protection Council (inaudible) Study and our own study,
9 that dry cooling is not feasible at Diablo Canyon, but
10 close cycle wet cooling would be. And some of the other
11 impacts of that would be some, I believe it's seven
12 million tons, 15 million pounds per year of salt deposits
13 across the Irish Hills there and would cause (inaudible)
14 on the lines also (inaudible). And, essentially, I mean,
15 I can give you the long list. I'll shorten it very
16 quickly, cost impact on the order of 4 to 4.5 billion
17 dollars to retrofit. So we're in that, you know, air
18 quality, rock and water quality hard place. Along with
19 SONGS, which offers about seven million metric tons per
20 year (inaudible) benefit. And you just reverse that if
21 you ask us to retrofit in one year of down time, the two
22 plants would cost the state about 14 million metric tons
23 of greenhouse gas emission. And that's, of course,
24 assuming the most conservative, the cleanest gas fired
25 back-up right now. We don't anticipate geothermal

1 (inaudible). Just wanted to get that out on the table.

2 DR. JASKE: In previous response, as (inaudible)
3 referred to (inaudible) if there's been a termination for
4 Diablo Canyon?

5 MR. KRAUSSE: No, but PG&E was scheduled, I
6 believe, in 2005 or 6, to enter into an agreement that we
7 had negotiated and a Central Coast Water Board staff had
8 approved for many millions of dollars in (inaudible)
9 mitigation. But because of the pending rule and the
10 Riverkeeper litigation, that was put on hold by the Water
11 Board, they actually did not vote on the policy as I
12 understand it, or voted to reject it, the settlement. So
13 we have other mitigation and in fact, I was talking about
14 the Water Board. For the Coastal Commission, yes, we've
15 done other mitigation, in both the trails we've conveyed
16 easements, (inaudible) conservations (inaudible).

17 DR. JASKE: Okay, in our remaining time I think
18 we need to shoot for the question of transmission systems
19 improvement (inaudible). Transmission system upgrades are
20 at least partial substitution for (inaudible). Care to
21 offer some thoughts?

22 MR. MINICK: Well (inaudible) I'm not a
23 transmission (inaudible), but I've been at Edison for 35
24 years doing generation and resource planning for 25 of
25 those 35 years. There are various types of transmission

1 system modification and enhancements that might allow some
2 retirement of existing plants and still meet the
3 applicable reliability and operational considerations that
4 the ISO, I'm sure, is worried about just like us. But
5 transmission studies are highly dependent upon the
6 assumptions used for the analysis and there's not a single
7 specific fix or modification that would work for all
8 possible resource expansions in the future. This is quite
9 complex. We have to look at different scenarios and those
10 scenarios include load considerations, growth, new load,
11 new electric loads, new distributive generation, new
12 resources, the types and locations of these resources,
13 whether they have inertia, whether they're out of the
14 basin, whether they're in the basin. It is a very, very
15 complex thing to do. So, no, there isn't one magic bullet
16 that says fix it like this and it's all solved. We have
17 to work with other utilities when we do transmission
18 plans, with the ISO when we do transmission plans. We
19 have to take a look at these scenarios into the future to
20 see what's the optimum mix. And I think many of the
21 panelists today have said there may be better fixes and
22 optimal fixes, what's the cost and the reliability
23 considerations of all these fixes? It's not something
24 that I can do overnight. I don't think the ISO can do it
25 overnight. I don't think any environmentalist can do it

1 overnight. We're going to all have to work together to
2 see what is the best optimum fix for this state to keep
3 the lights on and try to mitigate a lot of these
4 environmental concerns.

5 DR. JASKE: Let me ask PG&E if you could just
6 answer (inaudible) follow up?

7 MR. HATTON: Sure. You know, Mark brings up a
8 lot of good points. It is a very complex issue and PG&E
9 believes that a system reliability study should
10 (inaudible) regarding (inaudible) and perhaps the
11 (inaudible) ISOs and (inaudible) study these alternatives
12 (inaudible) planning process. PG&E believes that it's
13 critical to conduct a study of these alternatives
14 expeditiously because any delay could limit the number of
15 options potentially available by 2015 to the (inaudible)
16 transition away from some of these (inaudible). In
17 analyzing a process to (inaudible) units, a key area for
18 PG&E is the (inaudible). It's a local capacity
19 reliability area that contains a significant number of OTC
20 units. (inaudible) area transmission upgrades are likely
21 to (inaudible) of any longterm process to phase out the
22 OTC facilities. These infrastructure improvements could
23 include both additional ability to move power over power
24 over lines as well as the (inaudible) support devices. It
25 is likely that some of these improvements could be

1 retrofitted from existing facilities. But others may
2 require the need to put up new lines or new substations or
3 other transmission devices. In addition, as Mark says, it
4 needs to take into account other uses of these facilities.
5 These facilities are used for the Greater Bay Area to
6 solve a Greater Bay Area problem, but they're also used,
7 for example, as perhaps (inaudible) additional ancillary
8 services to support additional renewables and we'd take
9 that into account (inaudible) the services that these
10 resources currently provide. PG&E has commissioned a
11 study of OTC (inaudible) scenarios which was conducted by
12 Quantum Technology, to look at this issue and some of the
13 highlights of findings that they had come up with were
14 that retiring generation in the Greater Bay Area without
15 replacing that generation would require transmission
16 system reinforcement, possibly new transmission lines and
17 an increase in (inaudible) system will be able to support
18 devices within the Greater Bay Area. And since the
19 Greater Bay Area system is already heavily compensated,
20 numerous voltage support devices will not alleviate all
21 constraints that would be created by retirement of these
22 units in the area. So therefore, new, either rebuilt, or
23 repowered, or new generation, within the Greater Bay Area
24 would be essential to maintain the proposed transmission
25 system.

1 DR. JASKE: Is this study by Quantum that you
2 mentioned publicly available?

3 MR. HATTON: Yes it is.

4 DR. JASKE: Okay, if you could give me a
5 citation please, I'd appreciate it. Mr. Anderson?

6 MR. ANDERSON: On our transmission (inaudible)
7 and I will also. (inaudible) being a planner, being
8 around, you know, this industry a long time, to me there's
9 no doubt we're going to need more transmission and it's
10 not just going to be that will make the (inaudible) goal
11 issue. As we get more and more renewables on the grid,
12 the transmission to get the renewables here, I think the
13 ISO is going to find the more transmission it has, it will
14 be able to deal with the swings better, will be able to
15 deal with the ramps better. So I think transmission is
16 going to be part of our longterm solution. I'm not sure,
17 though, it's going to be targeted just (inaudible). The
18 other issue there is, and we've just been through it, it's
19 probably 10 years from the time you start your planning
20 until you get a major line up. And if people (inaudible)
21 before that 10 year period, I'm not sure transmission is
22 going to be (inaudible).

23 DR. JASKE: You indicated earlier that zoned
24 project additions could allow the retirement of at least
25 some of the (inaudible). You see a solution for the

1 remainder of the Encina facility?

2 MR. ANDERSON: I think that will come through
3 new additions in the San Diego area.

4 DR. JASKE: New gen?

5 MR. ANDERSON: New gen, yeah. Yeah, this
6 question was a little bit remote gen, I think we're going
7 to do what we can to get it, our replacement gen still
8 (inaudible) the load center. Because I think we're going
9 to need it there, given all the renewable power that we're
10 trying to bring in. So I (inaudible) the fossil that I
11 can maybe pick where it gets located a little bit better,
12 closer to load, and fill up my transmission lines with
13 fossil.

14 COMMISSIONER BRYON: Excuse me, follow up, how
15 do you, how do you pick where it's going to be located?

16 MR. ANDERSON: It's actually the last panel that
17 basically picks and they (inaudible).

18 DR. JASKE: Mr. Tharp, can you give us any idea
19 of the extent to which transmission system changes offer
20 any opportunity for OTC reduction in Los Angeles?

21 MR. THARP: I don't think it offers much
22 opportunity for reducing the need for generation in the
23 southern part of our system. We are doing -- we have
24 several transmission upgrade projects in the works right
25 now. I think everybody knows building transmission,

1 getting it sited and permitted is very difficult. We have
2 three or four of those that are working (inaudible) import
3 capacity for renewables. We're also doing some
4 strengthening of our central belt lines to our generating
5 stations, but even with those strengthening projects, it
6 won't eliminate the need for generation in that area into
7 our system.

8 DR. JASKE: Over the decades, as Southern
9 California has become increasingly urbanized, is it the
10 case that you were sort of locked into the transmission
11 system, you know, in your actual service area as it exists
12 today and there's little if anything that can be done to
13 change that?

14 MR. THARP: As a general statement that's true.
15 I mean, there are some small things we could do, but much
16 of our transmission has been built up, there's been things
17 built around it and we are, in essence, kind of blocked
18 with what we have.

19 DR. JASKE: So would it be going to far to say
20 that it's essentially infeasible to build transmission
21 that would, over to the western area, where Scattergood
22 is, that would allow Scattergood to not operate, or
23 operate perhaps only in some very rare contingency?

24 MR. THARP: I would think that would be very
25 difficult.

1 DR. JASKE: Is it simply difficulty of
2 developing transmission in a highly urbanized area like
3 that or are there particular permitting issues of doing
4 so, you know, just where the right of way wouldn't
5 actually be in the city of Los Angeles. Are there
6 particular permitting issues or complications of that
7 later sort?

8 MR. THARP: I think so, yes.

9 DR. JASKE: Do either of you gentlemen from
10 Edison have any comments on that particular side of the
11 problem?

12 MR. MINICK: Well, certainly, we (inaudible) do
13 transmission studies all the time and the ISO does local
14 capacity requirement studies to say what we need every
15 year, and the number changes with the kinds and types of
16 resources that we have. We've also, we have to look out
17 for how the grid might develop in the future by importing
18 renewables. We do have plans to upgrade some of our
19 facilities, but as everybody here has said, if I'm going
20 to increase my backbone in the LA basin, which is the
21 main, my main transmission system and convert 220s to
22 500s, siting and licensing that is extremely difficult.
23 It might be possible, but I'm not the expert to say it is
24 possible. We would have to do that. If you're going to
25 replace generation along the coast you're going to have to

1 increase the voltage on your backbone and taking
2 (inaudible) more power. And as we've said, it's probably
3 going to take 10 years to do that, so even if it was
4 possible, and, again, I can't say whether it is or isn't a
5 possibility. The ISO's looked at it and we've looked at
6 it. It's going to require quite a bit of time, and so the
7 Water Resources Board (inaudible) flexible thing. Let us
8 look at it, let us recommend it, let's look at the new
9 resources to try to do it. It's going to take some time
10 to do it.

11 DR. JASKE: Let me just try to press you one
12 more step and are there areas of coordination between the
13 Edison system as it's adjacent to LADWP that offer any
14 opportunity here, aside from all the jurisdictional issues
15 that are obvious?

16 MR. MINICK: I don't, LADWP can answer for
17 themselves. I haven't studied any more interconnections
18 to your grid to see if we could beef it up together. We
19 have a joint operating agreement that we honor. We have
20 areas where we connect the two systems. I don't know of
21 any studies recently that we've looked at trying to prop
22 up voltages on the two systems.

23 COMMISSIONER BRYON: They don't talk much. If I
24 may, just maybe one or two follow on questions. This is
25 very helpful. I think we're all in agreement. We have a

1 formidable problem ahead of us here. But given Mr.
2 Anderson's comment earlier about he doesn't prefer to give
3 out RFPs for one respondent and, of course, Mr. Krausse
4 indicated that PG&E's taken care of most of their
5 problems. The only real issue in the long run is the
6 nuclear unit. So maybe I'm directing this question to
7 Southern California, but is there, are there changes that
8 we can make that, I mean, thinking outside the box a bit,
9 so the procurement process that might be able to address
10 once through cooling.

11 MR. MINICK: Well, again, I think Gordon can
12 answer most of it. We have signed some solicitations for
13 some new projects that might help shut down existing
14 plant. But there are right now locked up in litigation at
15 ROCPM10.

16 MR. SAVAGE: Yeah, that's essentially, I think
17 we need a solution to the PM10 if we're going to build
18 anything more in the basin. I know the gentleman from
19 South Coast is here as well, he, I know they're working
20 and trying to make it so you can use existing plants, the
21 offset from the plants to be able to build. I know he's
22 working on this and it's going to take about a year or so
23 to have that fixed. And once we have that, then, we'll
24 have a better app forward. Right now there's an awful lot
25 in the air. We have (inaudible) is an issue, we have

1 PM10, and we've got direct access that we're looking at
2 and we're also looking at (inaudible) integrating maybe
3 33% renewable. It makes it very hard to predict,
4 (inaudible), let's do an RFO that's going to take us 18
5 months and then 18 months to three years, whatever it may
6 be, and then once we get through that, then it's two to
7 three years to build the project. It's very hard to make
8 choices right now.

9 COMMISSIONER BRYON: Right, but I hope you'll
10 agree that this is one of the things that we want to
11 explore a little bit further as to how we might be able to
12 use the procurement process proactively here to help
13 address this issue. Mr. Tharp, forgive me if I'm, if I'm
14 asking you to repeat something again, but I just wasn't
15 clear in terms of clearly the approach, the rule that the
16 State Water Resource Control Board is going to promulgate
17 will apply across the board here, you've got some units
18 that are in harms way, so to speak. Is LADWP's plan to
19 repower those units?

20 MR. THARP: As of right now we've got plans
21 announced, I mean, we've done two repowerings in the past,
22 we have two more that are on the horizon and that are
23 caught up in the PM10 issue, and that's all we have on,
24 that we can see on the horizon. Certainly you can look
25 forward and say, well, probably beyond 2015 we would need

1 to do additional repowerings, but our system needs sort of
2 go out for these two repowerings, one at Aines and one at
3 Scattergood.

4 COMMISSIONER BRYON: Okay. Mr. Jaske, any other
5 questions?

6 DR. JASKE: Not in the (inaudible).

7 COMMISSIONER BRYON: You've kept, put us back on
8 time. Gentlemen, thank you very much for being here.
9 This is extremely helpful and I'll reserve, I hope you'll
10 be here for the closing remarks because I think Mr.
11 Mansour and I both have some conclusions to draw about all
12 the things we've learned today. But, again, thank you
13 very much, we're going to need your continued help.

14 COMMISSIONER BYRON: Welcome, everyone. I see
15 that we still have Dr. Jaske moderating our panel. I'm
16 glad to see that. And, Dr. Jaske, I'll hope you'll
17 introduce all these people to us.

18 DR. JASKE: Yes, I will. And we have a little
19 bit of a complication. One our panelists, the
20 representative from NRDC, is not yet here, and Mr. Geever
21 actually has a plane flight. He needs to leave at 4:15,
22 so I'm wondering whether in this particular instance if I
23 work to essentially have each of the panelists run through
24 the questions, you know, individually on behalf of their
25 organization. And then to the extent that the NRDC person

1 comes, we'll be able to do that.

2 So, Mr. Geever, maybe we'll just start with you
3 and if you could take a look at the questions attached to
4 the agenda and then I may have some -- and give your responses,
5 and I may have some follow up for you as we go along.

6 MR. GEEVER: Thanks for accommodating my flight
7 schedule there. I appreciate it.

8 Yeah, well, I'll tell you, I've prepared a long
9 list of responses to these questions before I got here.
10 And now that I've listened to the presentations, so I'm
11 going to try and wing these.

12 I actually think that number four is the one
13 that perplexes me the most after having listened to the
14 other panelists. It's that, you know, the question of is
15 delay actually going to help implement this OTC policy or
16 not. The probability that once a policy is developed it
17 will be actually implemented. Well, look, I guess at the
18 risk of oversimplifying this, developing a policy that
19 won't be implemented is kind of pointless. So if it won't
20 do that, then there's no point in delay.

21 It sounded this morning like CA ISO had some
22 amendments that they were going to offer that I'm not sure
23 it necessarily meant delays in the policy but some changes
24 to the policy that would -- that would help resolve some
25 of these complications that you're dealing with.

1 I'm not going to speak for anybody but Surfrider
2 Foundation, but we're certainly open to solutions, any
3 kind of creative solutions that resolve multiple problems
4 at the same time. But without having seen the
5 recommendations they're making, it's impossible to say
6 whether we will support that or not.

7 DR. JASKE: Well, let me in looking at these
8 questions now again, I can see they probably could have
9 been tightened up a little bit.

10 One interpretation of the first sentence of
11 question four was the following: Previously, the Water
12 Board proposed 2015 as the compliance date for the low
13 capacity fossil plants converted into 2016, 2017, 2018,
14 you know, whatever, some set of dates of that sort, but
15 those dates were compatible with the overall energy agency
16 planning process. Is that the kind of tradeoff that could
17 make sense to your organization?

18 MR. GEEVER: I'm sorry. If they were compatible
19 with?

20 DR. JASKE: Is that a change relative to the
21 Water Board's previous 2015 compliance date that you could
22 live with? With the implication being that 2015 is sort
23 of an artificial date that wouldn't necessarily happen in
24 the real world. It might be on someone's rule book, but
25 you know as the date came along and the replacement

1 infrastructure wasn't, you know, ready, then presumably
2 there would be a strong clamor for that compliance date to
3 be pushed back.

4 Whereas, if we go through this process and we
5 try to do the advanced planning and identify a compliance
6 date for planner plans that does seem compatible with
7 planning and procurements and construction timelines that
8 there might be more viability to those date than just
9 picking 2015 out of the air. And given that tradeoff, is
10 that something that your organization could support?

11 MR. GEEVER: Excuse me. I guess I wouldn't
12 characterize 2015 as picking a date out of the air. You
13 know there was one study conducted for the Ocean
14 Protection Council that seemed to suggest that with the
15 proper planning that that target date was doable. So
16 without any other studies to compare it to suggesting that
17 there are some benefits to prolonging that, I question the
18 plan. Just like I tried to say before, you know, we're
19 open to looking at those, but they haven't been offered.

20 Look, I'm over coastal and ocean issues, but it
21 doesn't mean that I'm not concerned about air quality. I
22 also breathe, so you know, I'd also like to make sure that
23 the Clean Air Act is enforced as well.

24 DR. JASKE: So maybe that's a good segue into
25 the first question --

1 COMMISSIONER BYRON: Right.

2 DR. JASKE: -- because the first question is the
3 basic tradeoff between doing something for OTC versus the
4 whole constellation of air, land use, visual consequences
5 of other replacement infrastructure.

6 MR. GEEVER: Yeah. You know I've heard some of
7 the panelists talk about, you know, doing this detailed
8 cost benefit analysis and making sure that we get the
9 greatest societal benefits from whatever policy. From
10 years of working on marine issues and marine life issues,
11 management of marine life, we don't know enough about
12 marine life to talk to relations of -- It's entirely
13 outside of our realm of capabilities. You can't monetize
14 marine ecosystem impacts like that.

15 So, you know, as much as I -- I guess I had a
16 little bit of training in economics and just enough to get
17 myself into trouble but also enough to suggest that that's
18 not really entirely doable at this point. And tradeoffs
19 seems to imply that, again I don't mean to put words in
20 your mouth, but, you know, are we going to fully enforce
21 the Clean Water Act or are we going to fully enforce the
22 Clean Air Act? Well, we're going to fully enforce both of
23 them. How we do that, you know, if CA ISO has a plan that
24 allows us a way to that, like I said, we're waiting to see
25 it.

1 I'll make this point. The Clean Air Act or the
2 Clean Water Act in 316(b) was passed 45 years ago. And
3 when they passed it 45 years ago, once-through cooling was
4 the common practice at coastal power plants. As much as
5 I'm sitting here today, the Congress did not intend for
6 once-through cooling to be the standard practice four
7 decades later. That's just, you know, as frustration
8 here.

9 Look, you've got to understand that we've been
10 waiting an awful long time for this law to be enforced a
11 year here or there. It's the desire of the environmental
12 community, but it's more important that you set a deadline
13 that we're going to stick to and that we're going to fully
14 enforce this law finally.

15 And if I can, I'll add one thing and one of the
16 panelists from the generators suggested that one of the
17 conditions, not to make even this more complicated, but
18 that, you know, there's co-relocated desal proposals out
19 there on the table now. You know, we're running out of
20 water and we have to take that into consideration.

21 Let me tell you just a couple of facts about the
22 co-located desal facility and how that relates to our OTC
23 policy and grid reliability and all these other kinds of
24 targets that we're trying to meet. This is the most
25 energy-demanding source of water you could ever devise.

1 It's 40 percent more energy demanding than pumping water
2 from Sacramento to San Diego to allow us to run that plant
3 and so on up and down coast, and each one of them is
4 expandable. That's an additional demand on a grid that
5 you're already trying to figure out to, you know, make
6 more reliable. This is not the answer to our water
7 problems. This compounds everything that we know about.

8 The water that they need for that plant is
9 actually more water than what they're withdrawing to cool
10 the power plant at this time. It's 11 percent more, so
11 you're adding 40 percent to the most energy-demanding
12 source of water and you're adding 11 percent more water
13 intake to run the desal facility. You've undermined all
14 of our policies.

15 To get back to your question number three, how
16 does your organization propose to participate in efforts
17 to remove the current inability to locate new power plants
18 within most of Los Angeles Basin? I don't know. You
19 know, it's really an unfortunate circumstance that, you
20 know, NRG wants to build a high-efficiency plant there.
21 And for some malfunction at the Air Quality Management
22 District, that thing is being held up. You know, I think
23 that those proposals are the kind of things we should be
24 looking at, and it's an unfortunate set of circumstances
25 that that project is being stalled.

1 So I'm open to suggestions of how we can help
2 with that project moving forward.

3 DR. JASKE: There's a considerable coalition of
4 groups who have been pursuing OTC. Can you imagine if
5 some or all of those groups, you know, somehow or other
6 participating in broader environmental issues, you know,
7 like the particular instance of South Coast's, you know,
8 air credit that you just mentioned and somehow or other
9 speaking from an overall environmental perspective?

10 MR. GEEVER: I'm disappointed that, you know,
11 our NRDC representative didn't get here on time to be a
12 part of this panel because I was looking forward to his
13 recommendations on creative solutions to this. And
14 because I don't work in air quality, I don't have those
15 kind of, you know, have recommendations for you myself.

16 But like I said, I'm not willing to sacrifice
17 full enforcement of one law for full enforcement of
18 another. But you know, this is a time -- This is a time
19 to start thinking creatively. It's a time to start
20 thinking creatively about water solutions and all sorts of
21 greenhouse gas emission reduction and adaptation.
22 Everything is on the table.

23 DR. JASKE: Thank you for stating that.
24 Question number two, which was the last one on the list,
25 and that is, of course, a non-power plant solution to

1 managing our electricity load situation is more energy
2 efficiency, more renewables that don't have any air or
3 water consequences at all, but we're already apparently
4 planning on relying upon those in unprecedented levels.
5 The ARB GHG scoping plan calls for major increases in all
6 those.

7 Do you foresee anything more than what's already
8 being planned in the level in the ARB scoping plan?

9 MR. GEEVER: Well, I can tell you within the
10 limited scope of the stuff that I work on, I mean I tell
11 people that, you know, now people wonder why is the
12 Surfrider Foundation is working on water supply stuff.
13 And I tell them I got sucked into it through a cooling
14 water intake, and the reason why is because of this idea
15 of using these intakes for desal. So not wanting to be
16 the naysayer to a new water supply, we've been looking at
17 a lot of water supply alternatives.

18 And I can tell you that it just shocks me that
19 it was surprising to find out that 20 percent the state's
20 energy usage is about moving water around. And if there's
21 a target for energy conservation and greenhouse gas
22 reduction, it's water. That's a big target that we can't
23 overlook and to come up with solutions that are energy
24 demanding than what we're doing now seems like backwards
25 thinking to me. But there's a lot of conservation that

1 can be had -- energy conservation that we can gain through
2 smarter water management, you know, adding the imbedded
3 energy component into our water management portfolios so
4 that's one thing.

5 And maybe I'll just throw this in anecdotally
6 because it was a thought that I had with trying to walk in
7 the door this morning was that now I have PV panels on my
8 roof. They don't cover my roof. I calculated them to
9 supply what energy every year or maybe a little bit goes
10 back into the grid. I was considering rather than rebates
11 for roof photovoltaics that, you know, the utilities get
12 into the business of installing those things.

13 Just imagine a system where, you know, a
14 homeowner was offered free PV cells for their roof, and it
15 would be more than they could use, and that they would
16 have to agree that the excess would go back into the grid.
17 We're talking about putting photovoltaics where there's no
18 concern about the habitat in the desert or any kind of
19 environment impacts. These are rooftops. It's not
20 habitat for anything. The problem of using energy and
21 undermining our efforts in conservation, you only would be
22 allowed a certain amount of free energy from those
23 photocells for your house. Anything over that, you'd have
24 to pay for just with photovoltaic cells.

25 I haven't thought this thing through, but I

1 think there's a lot of creative ways to get renewables out
2 there and get them out there really quickly. But the one
3 thing I do know is water. There's a lot of energy that we
4 can save in rethinking our water management portfolios.

5 DR. JASKE: Thank you. Thank you for agreeing
6 to sort of go solo here.

7 MR. GEEVER: Well, thank you for allowing me
8 that. I'd be glad to answer any questions.

9 COMMISSIONER BYRON: None. Okay. Mr. Geever,
10 thank you. I think we got your frustration. It's been a
11 long time. You want to see a rule implemented. And of
12 course, what we're doing here today is to try to
13 understand the complexities of how to go about a
14 reliability-based rule so that the electricity doesn't go
15 off in the meantime. But this will, I understand,
16 according to the State Water Resources Control Board, will
17 be promulgated this year.

18 MR. GEEVER: Like I say, I appreciate the effort
19 that you're going through here. I want to, you know,
20 breathe clean air. I like going home and turning on a
21 switch and having my light bulbs come on as much as the
22 next guy, and so, you know, grid reliability is important.
23 I wouldn't discount it, you know. Thank you very much.

24 COMMISSIONER BYRON: Thank you, sir.

25 DR. JASKE: Okay. I observed to myself

1 somewhere along the way I failed to introduce the
2 remainder of the Panel before I started quizzing Mr.
3 Geever. So our other panelists are Deborah Sivas with
4 Stanford Environmental Law Clinic, Angela Haren,
5 California Coastkeeper Alliance, and also Bill Powers from
6 that same group. Special thanks to Angela for helping me
7 identify these folks and arrange that they come here
8 today.

9 So who would like to go next?

10 MS. SIVAS: Are we just going to go in order?
11 Are we going to go back to --

12 MS. HAREN: Whatever you prefer. I
13 unfortunately received a message from the NRDC staff that
14 they're stuck in an Assembly hearing, so I'm not sure that
15 waiting that he'll be able to make it either way, so it's
16 up to you. We could go in whichever order you prefer.

17 DR. JASKE: Well, then why don't we just
18 continue. I actually prefer the crossways, so let's now
19 go to question one, and we'll just work our way across the
20 table.

21 So what about this question of tradeoff between
22 OTC mitigation and potential increase in adverse
23 consequence from new generation or new transmission?

24 MS. SIVAS: So I'll start. So just to let you
25 know, I teach at Stanford Law School, and the Clinic has

1 been involved in once-through cooling issues for about ten
2 years now with respect to a variety of different plants
3 along the coast, so we don't represent any particular
4 group. We've worked with everyone here at the table as
5 well as other groups. So I'm not going to come at it
6 strictly as, you know, what would your group think, but
7 trying to think more broadly about the coalition of folks
8 who are interested in these issues.

9 And I guess I struggled a little bit with these
10 questions, but just on the -- Wait. Let me just say one
11 other thing is that on the air issues, it's very
12 unfortunate that NRDC isn't here because I mostly have
13 been working really on the water side.

14 And from what I understand about the situation
15 in the South Coast, that is a very difficult. My sense is
16 that that somehow is going to work itself out. I wish I
17 had NRDC to talk about that a little more. But within,
18 you know, a relatively short time, we're looking at a
19 phase in of a policy over the next, you know, ten or
20 fifteen years, and I think there are a lot of other things
21 driving the resolution of the South Coast issue.

22 COMMISSIONER BYRON: I'm sorry. They're not
23 here either. It's going to work itself out? We would
24 really like to hear from them.

25 MS. SIVAS: I just don't think that the once-

1 through cooling is going to drive the resolution of that
2 issue. I don't know what that resolution is going to be,
3 but what I'm concerned about is not getting most of the
4 once-through cooling momentum we've got going off track
5 because we had one really difficult issue in the South
6 Bay. And I think there was talk this morning about you
7 may have air problems in other districts, too.

8 I don't think they'll be anything, from what I
9 understand, anything like what's the tangle that's
10 happening in the South Coast Basin so, you know, I really
11 hope that we -- that the state -- I'm very appreciative
12 that the agencies have come together to try work this
13 through because I think everyone here is concerned about
14 grid reliability as well, and we have to figure out how to
15 sequence this going forward.

16 I guess my message was just that, you know,
17 hopefully we don't throw out the baby with the bathwater
18 because the State Board has been working for several years
19 now trying to put a policy in place, and it may mean that
20 the pieces move a little bit but hopefully we don't just
21 delay.

22 Beyond the air issues, I think there are minor
23 issues related to alternative cooling. Ones that we've
24 often faced in some of the projects that have been
25 considered are aesthetics and green use issues. And I

1 think my sense is that those issues are not of a magnitude
2 of the ocean impacts and green life mortality, and those
3 issues even EPA, which studied these issues for a number
4 at a nation level but, nevertheless, looked at all of
5 these issues in their rule making and concluded that those
6 issues were negligible compared to the marine mortality
7 that everybody knows is going on, and that's why they
8 promulgated a rule that was fairly stringent going
9 forward.

10 There are small issues to be worked out, but I
11 don't think it's -- I think it's a false dilemma of it to
12 say that there are tradeoffs of the same magnitude once
13 you get beyond the air issues in the South Coast Basin.

14 MS. HAREN: Yeah. I would also like to agree
15 with what Debbie said, and hopefully I don't know if our
16 colleague from NRDC will make it here. But if not, we'll
17 definitely follow up with them and encourage them to
18 submit their comments in writing so that you can have
19 their input as well.

20 I also agree with Debbie that we don't believe
21 that we have to choose between protecting our water or
22 protecting our air. I think in terms of achieving the
23 various goals including reducing marine life mortality and
24 protecting air quality that we actually view phasing out
25 once-through cooling, if done properly, as a way to

1 achieve both of these goals.

2 I know there was a report from CA ISO a couple
3 of years ago noting that the majority of the old steam
4 generators using once-through cooling have higher
5 greenhouse gas emission rates than newer plants and that,
6 you know, many of them are beyond their expected lifespan
7 already, so we really view this as an opportunity through
8 the proper planning to achieve multiple goals.

9 And we, you know, trust that the agencies
10 responsible will do that, and we're encouraged that the
11 agencies have been meeting very diligently and working
12 through these problems. And we don't believe that
13 balancing how to implement these goals and achieve other
14 goals means that we have to sacrifice any of them. Just
15 as Joe said, we advocate full implementation of the Clean
16 Air Act and the Clean Water Act. And again we are here
17 willing and able to assist the agencies in any way that
18 they need to help to do that.

19 One thing I just wanted to mention, two things.
20 One is that today earlier we heard some specifics about CA
21 ISO's grid reliability research, but we didn't hear about
22 the State Board and Ocean Protection Council. They co-
23 funded a grid reliability study that was conducted by
24 Jones and Stokes. And I would just like the opportunity
25 to hear how the State Water Board is going to be taking

1 into consideration the results found in that study as to
2 what CA ISO is saying. So that study was released
3 publically, is very detailed, and was funded by taxpayer
4 dollars.

5 And so it's concerning to me that we didn't hear
6 much today about that study, and so I'm eager to hear how
7 the State Board is going to be or taking into
8 consideration that report. And if there are issues with
9 that report, we would very much like to hear them in a
10 public forum so that we can understand them because we
11 appreciate all the work that CA ISO has done, but so far
12 we've just seen some PowerPoint presentations online and
13 today and we haven't seen the details of that report. So
14 to the extent that some of the conclusions differ between
15 what CA ISO is concluding and what this other grid
16 reliability report is saying, it just would be nice to be
17 able to understand where those discrepancies are.

18 And then my last thing was just to introduce
19 again Bill, and just to clarify and point out that he is
20 here today on our request. He's a consultant and so he
21 has a lot of other expertise that California Coastkeeper
22 Alliance doesn't have, and also we appreciate him being
23 here.

24 MR. POWERS: Thank you. A couple of comments to
25 follow up and a little bit on my background. I'm

1 currently working on two nuclear system retrofits
2 projects, one in Connecticut and one in New York. These
3 units are the same size as the Diablo Canyon units and the
4 SONGS units, and I was involved in the Morro Bay cooling
5 system CEC process evaluation, as well as Palomar Energy.

6 And I'd like to reiterate the comment about ICF
7 Jones and Stokes. You heard the president of ISO talk
8 about a \$5 billion cost to meet with transmission and the
9 retirement of the Southern California coastal plants.
10 Jones and Stokes indicates that we can retire all of our
11 OTC boiler plants for potentially as little as \$135
12 million in transmission upgrades. That's almost a 50 to 1
13 difference in estimates on transmission costs to do this.

14 And I think a couple of the commentators from
15 industry made some very interesting comments that I agree
16 with, that you've got a ten, twenty, or thirty-year-old
17 car in the garage that works fine and is a very low cost
18 to operate. And with a cooling tower retrofit, you can
19 use it as reliable peaking power for many years to come.

20 And the other report that was mentioned that was
21 part of this Ocean Protection Council/State Water
22 Resources Board state-funded was the Tetra Tech report.
23 They indicate the cost to retrofit a boiler is about \$150
24 a kW a cooling tower. The industry representative, I
25 don't recall his name, said \$125 a kW for his fleet of

1 4,000 megawatts. Well, that's just about the same, so we
2 seem to agree that the cost of a cooling tower retrofit on
3 a coastal boiler at \$125 to \$150 a kW is in the range of
4 one-tenth of what it would cost for LMS100 peaking gas
5 turbine installation. This is at least \$1,000 a kW.

6 The same can be said of the combined cycle
7 project, Moss Landing combined cycle and Haynes. The
8 Tetra Tech report estimated \$70 a kW for the refit to a
9 cooling a tower. Cost for combined cycle new capacity
10 there \$800-plus according to the CEC, a factor of ten
11 greater.

12 The nuclear plant -- I work a lot with nuclear
13 plants and I don't know if the PG and E representative is
14 still here, but I think he said \$4 to \$4.5 billion to
15 retrofit it.

16 DR. JASKE: That's correct.

17 MR. POWERS: Well, the Tetra Tech report said
18 \$700 million. The project I'm working in Connecticut,
19 which is the same size unit, in 2001 at Dominion Nuclear,
20 the company estimated \$126 million to retrofit it. The
21 cost should be \$200 to possibly \$400 a kW. A new nuclear
22 plant is minimum \$7,000 a kW, a factor of 20 greater than
23 retrofitting these nuclear plants.

24 And another comment to make is those plants are
25 in the process of their steam generators are being

1 retrofitted at both Diablo Canyon and SONGS. These are
2 \$700 to \$1 billion projects that the utilities did not bat
3 an eye about doing because they want to keep the plants
4 running. And the trade press has indicated that they have
5 done spectacularly well on I think Diablo Canyon 2, 69
6 days to do a searchable opening of the reactor housing and
7 change out the steam generators. If it is mandated, it
8 will get done, and it will get done effectively and fast.

9 And again, I just want to reiterate on this
10 point that -- or one other point. Despite comments in
11 here that we need all of the coastal OTC plants, we did
12 see a presentation from the CEC today talking about
13 resource adequacy contracts showing essentially none of
14 these coastal or nonnuclear plants are under any type of
15 resource adequacy contract from 2013 forward. Others know
16 no one at the state level is saying we have to keep these
17 plants operating. And it should be either they can
18 compete or we need them and we retrofit them at ten cents
19 on the dollar so they continue to provide reliable peaking
20 power. This is not complicated, it's not expensive, and I
21 don't really see much of a tradeoff. Thank you.

22 DR. JASKE: I can offer clarification about the
23 chart in Mr. Vidaver's presentation. The current resource
24 adequacy process only requires load serving entities to
25 identify the resources that just satisfy their obligation

1 in a sort of stylized "year ahead" process. It has been
2 the practice that some load serving entities enter into
3 multi-year forward contracts because it essentially is
4 cheaper for them to secure, you know, the services of a
5 generator by doing so as opposed to just a set of serial
6 one-year ahead contracts.

7 So that display of information is the
8 compilation of what in effect is voluntary contracting
9 forward because it's cheaper for the ratepayer. It
10 shouldn't be construed as meaning that there isn't a need
11 for those plants, you know, in years forward. Just that
12 that's the level of contracting that exists today under
13 this resource adequacy process and the voluntary multi-
14 year forward contracting arrangement, but it is a better
15 deal for the ratepayer.

16 MR. POWERS: Does that mean that the \$4 to \$4.5
17 billion comment was unrelated to the actual cost of
18 retrofitting Diablo Canyon with cooling towers? I didn't
19 quite follow. The number stuck in my head, but I did not
20 follow that it was -- I followed it as directly connected
21 to the retrofit of Diablo Canyon.

22 DR. JASKE: I believe that's correct, but that's
23 a cost he was indicating that would be necessary because
24 they anticipate using that plant available to the -- Let's
25 put it that way. Whereas, the contracts with all the

1 merchant plants there isn't yet a mechanism that requires
2 in the long run of capacity contracts beyond just a one-
3 year ahead process.

4 Mr. Lueze actually referred to the desirability
5 of having, you know, a further forward capacity of market
6 or a capacity requirement because that would bring more
7 ability to the merchant generators to sort of understand
8 their role going forward, but it doesn't exist as of the
9 moment.

10 Well, let me then turn to question two, and you
11 know sort of observe that in particular the plans put
12 forward by the PUC and Energy Commission to ARB and built
13 into their 8032 scoping plans called for, you know, very
14 high levels of energy efficiency in renewables and so that
15 tends to diminish the amount of fossil generation needed.

16 Do you anticipate your organizations, you know,
17 anticipate, you know, more than those levels or do you
18 think that, as outlined in the ARB scoping plan, that
19 that's a good faith effort to sort of maximize the use of
20 those resource types and diminish the amount of fossil
21 generation necessary?

22 MS. SIVAS: So I'll start briefly. As I noted
23 before, since I don't represent any particular
24 organization, this question and the next one were a little
25 difficult for me, but let me just respond to it this way,

1 and that is on once-through cooling issues, we've worked
2 with a coalition of groups interested in bringing issues.
3 We also work with groups who are very heavily involved
4 including NRDC, one of them, on AB 32 and greenhouse gas
5 emissions.

6 And my sense from all of that work is that there
7 probably are things that people want to come forward with.
8 Having solar on everyone's rooftop was an interesting
9 suggestion, but you know I'm not prepared to speak to
10 those today because I think those groups need to speak for
11 themselves.

12 But I wanted to just get back to I think an
13 issue that you raised when Joe was here, which is, you
14 know, are these groups working together? And I think the
15 answer to that is yes. And I think from what I've seen,
16 the groups have been very thoughtful.

17 So you have folks here at the table who are
18 mostly working on green issues, you have other folks
19 interested in air issues, other folks in particular on
20 greenhouse gas issues, and I think there is a lot of
21 discussion that the environmental community is trying to
22 do across these subject matter areas recognizing, you
23 know, that they interrelate in various way. And so I do
24 find that a hopeful sign and that we're not going to get
25 groups in silos based on, you know, their substantive

1 expertise, but I think everyone recognizes the climate
2 change issues are really very paramount these days, and
3 that folks are trying to work together,

4 So it's a little bit off point with your
5 question, but I just did want get in there that I don't
6 think the groups are thinking only about the substantive
7 issue but really trying to think more broadly across the
8 media and across the, you know, like NRDC has additional
9 things to bring to the table in energy efficiency and
10 demand side.

11 MS. HAREN: So again, we focus mostly on clean
12 water and marine protection, so we have not been involved
13 with -- to the extent that -- to extent with how it plays
14 with water conservation and water supply and once-through
15 cooling, so we haven't specifically been advocating. So
16 to answer your question of whether or not we think that is
17 sufficient, I don't have the answer to that. But I can
18 also say that we're not a group that would go advocating
19 for anything different with the greenhouse gas emissions
20 because we don't work on that.

21 But that said, we are working very diligently
22 with water conservation, water recycling, and other
23 policies that we feel will really help to reduce the
24 amount of energy that California spends on conveying
25 water, which is something that Joe talked about. And

1 we've been working in concert with the State Water Board.

2 And you know I think that everybody pretty much
3 on the planet at this point realizes that global warming
4 is an issue and that it's not something that's our
5 environment. And so we've been thinking very hard about
6 how we can promote policies to both protect our water and
7 hopefully reduce the energy demand and thereby reducing
8 greenhouse gas emissions. So I would say that, you know,
9 we're really proud of all of the work that California has
10 been doing and that the agencies have been doing, and
11 we're supportive about it and just trying to move forward
12 as we can on the water side of things.

13 So I'm not quite sure if that answers your
14 question, but that's the best I can do from my water side.

15 DR. JASKE: Bill, anything you want to add to
16 that?

17 MR. POWERS: A couple of points, and one isn't
18 directly related to greenhouse gases but it was brought
19 out in the ICF Jones and Stokes report that between 2001
20 and 2008, we added in California 7,000 megawatts of
21 generation. And at the time a year ago, there was at
22 least 2500 megawatts in construction, so approximately at
23 this point I would assume about 10,000 megawatts of
24 generation added. Whereas, today it almost seems as if
25 we're talking about a static environment where these

1 plants are part of a null set equation.

2 Going to the greenhouse gas issue, in 2008 the
3 CPUC initiated a rule that the utilities must now achieve
4 all cost-effective energy efficiency. And the graphs that
5 they produced as a result of that ruling show our energy
6 demand per year dropping between now and 2016. The target
7 in 2020 may be 15 percent reduction in gigawatt hours per
8 year. Demand response, without taking into consideration
9 central air conditioning or air conditioning issues,
10 stayed flat for ten years. If we achieve these targets,
11 there is no -- the context of this discussion isn't with
12 relentlessly rising demand. The context is dropping
13 demand and at worst case flat peak demand but probable
14 drop in that as well.

15 Talking specifically greenhouse gases, the
16 California Energy Commission is at a point of potentially
17 making a historic decision in a peaking power plant case
18 in Chula Vista, the Chula Vista energy upgrade project
19 where May 27th the CPUC Commissioner will be voting on a
20 denial of 100-megawatt peaker plant. One of the elements
21 in that denial was that the applicant did not evaluate to
22 any detail what the CEC is at least identifying as a cost-
23 effective photovoltaic alternative to the peaker plant.

24 Presumably if that denial holds, what it means
25 is that every future peaking power plant, and since these

1 once-through units are basically being used as peakers,
2 the nonnuclear plants, would be -- the litmus test would
3 be could you replace that capacity with photovoltaics?
4 And so I think the CEC is going in exactly the right
5 direction in maximizing the deployment of urban
6 photovoltaics as just a new solution to an energy supply
7 problem.

8 DR. JASKE: I think I heard earlier today some
9 comments that sort of the capacity in the peak wasn't
10 itself, you know, a sufficient replacement for the
11 capabilities of these plants. That, in fact, there were
12 needs for the flexible plants to deal with the
13 intermittency of wind and you know the load itself. So
14 did you -- were you here to hear that and do have any
15 comment about that distinction between, you know,
16 photovoltaic versus a dispatchable plant.

17 MR. POWERS: Yes. You do not need to backup
18 photovoltaic power with gas turbines. That is a fallacy.
19 And I think that the press nationally that looks at this
20 like Public Utility Fortnightly is coming out with
21 comparative studies showing that when you really need the
22 power, which is hot, sunny days, you can rely on the
23 output of the PV systems. If you desire to match the
24 output profile of a summer day, you can add a limited
25 amount of cost-effective storage and rely on PV systems,

1 I'm distinguishing them from wind systems, rely on them
2 for summertime peak power.

3 And I think that the issue of backing up wind
4 power with a gas turbine just begs the question, if we
5 have adequate capacity today to meet our power needs, why
6 would we be building a new generation of peaker plants to
7 backup wind turbines? Those wind turbines would be
8 cutting into existing capacity and we will backing off the
9 fossil units. We won't be -- We will not have a need to
10 duplicate the nameplate of wind turbines with gas
11 turbines, and I think that is an important point because
12 there's a lot of talk about adding a lot of capacity to
13 back the renewable energy. I don't think that's the way
14 it should be handled in a world of declining electricity
15 demand.

16 MR. MANSOUR: Mr. Jaske, I really come up to
17 differ. Put it this way, you have the data that is, I'm
18 afraid to say, very misrepresented, and I can go through
19 every line of it that I would suggest that you check it.

20 MR. POWERS: What data is this?

21 MR. MANSOUR: Well, let me just go through one
22 by one. First of all, let us just understand there's a
23 difference between energy and capacity for energy and
24 demand. Demand has been increasing. Actually, in April
25 just last month, we had three days of above usual

1 temperature, and we recorded at ISO the highest air load
2 demand our end.

3 So there's a difference between demand and
4 energy. Yes, there will be more energy especially from
5 the -- as the 20 percent renewables come in, but the
6 peak -- summer peak heat phase that we're talking about,
7 the performance of wind at the peak time was five percent
8 or less than the energy capacity. So you point out, no,
9 you don't need to have this duplication. That is not a
10 duplication when there is primarily an energy source and
11 not a capacity problem. So that is still just
12 (inaudible). These are facts. These are scientific
13 facts. I'm not talking about the debate between
14 reasonable people. I'm talking about scientific facts
15 backed by real data.

16 The second thing is that you mentioned that
17 someone has \$1.7 -- \$117 million to fix all the
18 transmission constraints in the system. Frankly, if you
19 have the name of that person, I'm sure there's some kind
20 of big sale or something like \$117 million and let them
21 fix all the stuff in the state as you're saying.

22 Let me just give you some data on the cost that
23 actually are things that are underway. The project that
24 was offered in the retirement of unit 3 of Potrero was
25 \$450 million cable for transmission. And the cost of

1 Jefferson Martin 230 kV, which is in part resulting in the
2 retirement of the Hunter's Point, was \$230 million.
3 Potrero and Hunter's Point, 115 kV cost is \$100 million.
4 These are costs that are already incurred to replace some
5 of the local capacity needs by transmission.

6 So, you know, for someone to come and say all of
7 those locations can be replaced or done by \$117 million
8 that is a severe misstate of the facts on what the cost of
9 transmission is. And if that were the case, we wouldn't
10 even need OTC. Every time I'm going to sign one of those
11 generators to actually pay them to stay, we compare their
12 costs to the actual cost of transmission that would
13 actually get rid of them. And in every case, they are
14 much more cost efficient than putting generators in, so
15 that is another one.

16 The second thing is you have seen the static
17 that there's 15,000 megawatts or so of OTC capacity in the
18 state. Replacing that capacity -- We're not talking about
19 the local level now. You heard the people talking about
20 resource adequacy for the system as a whole. Replacing
21 15,000 megawatts of capacity, even if we say that some of
22 the demand response and all of that will reduce it even a
23 few thousand, you're still talking well over 10,000. Now
24 the replacement of that capacity, since you still need it,
25 is even not counted in \$4 or \$5 billion, and it is

1 significantly more than that right now. So we're talking
2 about just the transmission cost and not the replacement
3 cost of replacing the capacity.

4 So we're all trying to solve the issue and we're
5 all trying to not put cost entirely as a reason not to
6 proceed. In fact, it is the opposite. But to actually
7 state facts like you just mentioned, which is totally off,
8 (inaudible) I just stand to differ. And that's just kind
9 of discussing along with these of lines of numbers it does
10 not -- really all facts show that is not true. For me,
11 it's not helping.

12 DR. JASKE: You care to respond?

13 MR. POWERS: And I think this is -- Mr. Mansour
14 brings up a very important point, which is the
15 environmental community is working with the ICF Jones and
16 Stokes report -- reliability report. If the ISO doesn't
17 have it or hasn't read it, that's a problem because what
18 that reports states is that with a phase-out over the next
19 years, we can retire all of the coastal OTC boiler plants.
20 And what we would need is a minimum upgrade --
21 transmission reinforcement upgrade, a value of \$135
22 million.

23 The ISO may disagree with that report and those
24 numbers; however, that report is much more detailed than
25 anything the ISO has put out to backup their claim of a \$5

1 billion expense to replace with transmission the
2 retirement of OTC boiler plants in the South Coast. And
3 so I think that in some ways we're getting where we should
4 be, is that ISO needs to read ICF Jones and Stokes, needs
5 to critique it, needs to present their case so that we can
6 find the truth of the matter.

7 MR. MANSOUR: As I said, sir, if you have
8 someone that is willing to take \$117 million and solve all
9 those problems, I am sure I can get all of us together and
10 write a check for \$117 million and solve them all.

11 MR. POWERS: I will see you at five p.m.

12 COMMISSIONER BYRON: Gentlemen, I'm hoping --
13 Thank you both very much, very good interaction. Let's
14 try and get back to answering these next couple of
15 questions or maybe we only have one left, Dr. Jaske, and
16 then we'll open it up for public comment.

17 DR. JASKE: I think, yes, we are basically down
18 to question four, and as I indicated in my back and forth
19 with Mr. Geever, that it's written and it's probably not
20 as clear cut as it could be. So it was originally
21 intended to contrast the March 2008 notion that most of
22 these plants would have to retire or they would have to
23 comply, and I guess it's the super position of the staff's
24 opinion that they would, in fact, retire by 2015. And
25 that as that date grew closer, it would be realized as not

1 feasible and, therefore, it would be pushed back. So
2 there was the appearance of near-term compliance date.

3 Now contrast that with this effort over the last
4 six months is emerging in which it might on its surface
5 show more protractive compliance but it's at least more
6 backed up with firm specifics for the various plants, you
7 know. How does that -- do you react to that sort of
8 contrast?

9 MS. SIVAS: Thanks. Yeah, I think as Mr. Geever
10 said, you know, a lot of us have been at this for long
11 time. And so I think if we're talking a year here to two
12 on the margin, there may well be some value to looking at
13 it in a way that makes sense of it, you know, but we're
14 not five years or ten years down the line and having to
15 push off things because of assumptions that we made today
16 and we're not realistic.

17 So, sure, I think if we're all worried about
18 grid reliability, it seems if a policy is based on trying
19 to look at the system as a whole and deal with grid
20 reliability rather than the State Board's original
21 proposal, which was based on the capacity factor for a
22 plant, I think that, you know, that makes a lot of sense
23 there, you know.

24 As Jeff said, we haven't even seen what that
25 might look like. It sounds like it won't look

1 dramatically different. Certain things may shift a year
2 here or there. But my own view is that the key is really
3 putting -- the key here is to put a policy in place and
4 have the industry working towards that policy, and I think
5 that has been the biggest problem.

6 Even as you know, there's been litigation at the
7 Supreme Court and some uncertainty over the federal
8 policy, and the state has stepped in and is trying to
9 bring I think some order to what has been a little bit
10 chaotic at the federal level. And I know that dealing
11 with the individual Water Boards the concern is always we
12 don't know what the policy is, or where the policy is
13 going, we're trying to interpret this.

14 So what we've been pushing is let's try to
15 create a realistic policy, put it in place, and create the
16 incentives and milestones for the industry to be aiming
17 at. I would say, and I think it was confirmed by the last
18 panel that was up here, is that we're looking ultimately
19 at retiring some of these plants probably because they're
20 quite old or repowering.

21 And in every case, almost every case where the
22 companies are talking about repowering, they are actually
23 looking at alternatives to once-through cooling. And I
24 think that's a lot because they're seeing the writing on
25 the wall. And I would say ten years ago when we first got

1 involved, that was not the case, and I think sort of the
2 policies at the federal and state level are really driving
3 that market.

4 So I think the key thing is to try to get
5 something in a reasonable timeframe in place. And if it's
6 built around the agencies' judgments about grid
7 reliability and how put those pieces of the puzzle
8 together, you know, I think that that's something that can
9 be workable.

10 I mean I guess I would say the one thing is, if
11 we don't get a policy in place, what you're likely to see
12 is right now we have a number of coastal plants that are
13 on kind of long extensions of their Clean Water Act
14 permits, which those are five-year permits, and they're
15 supposed to be renewed every five years. And they're
16 supposed to actually ratchet down technology because the
17 Clean Water Act is a technology forcing statute. And so I
18 think what you're going to see, if you don't get a policy
19 that's in place with some implementable dates, you're
20 going to probably see more litigation around the
21 individual plants, which really doesn't do any of us any
22 good on either side of the equation.

23 MS. HAREN: Thank you. So again, we obviously
24 haven't seen the exact proposal and what the dates are, so
25 I can speak to the specifics.

1 But just generally speaking, I just wanted to
2 underscore something that Mr. Bishop said earlier, and the
3 fact that this type of massive fish kill would not be
4 tolerated by the State Board for any discharge. And the
5 truth is that an untold number of marine species are being
6 killed, and we're also facing, you know, the decline and
7 collapsing of several of our major fisheries, and so this
8 is obviously an important issue.

9 It's also important to note that peak larval
10 abundance corresponds with -- well, it usually happens in
11 the summer, and that corresponds with, as you've heard,
12 when some of these plants that aren't used very often but
13 when they are used they're used during the peak larval
14 abundance, so it's important to note that.

15 So with that backdrop, we think any undue delay
16 is not going to be beneficial in any way. But we do agree
17 that proper planning and timing is really important. We
18 also strongly believe that deadlines for compliance are
19 critical if we're going to achieve these goals.

20 So we've been encouraged that the interagency
21 working group has been working together, and really look
22 forward to seeing the State Board's policy come out. I
23 think that, and I hesitate to say this, but the exact
24 deadline is not as important to us as the fact of having a
25 policy in place with a deadline.

1 So hypothetically, let's say we have a policy
2 that has a ten to fifteen-year phase-in approach. It's a
3 big difference for the fish if we pass that policy today
4 or in 2009 or is we pass it in 2011. So ten to fifteen
5 years from today is a lot different than ten to fifteen
6 years two or three years from now.

7 So I would say that, you know, we recognize what
8 a complex issue this is. There are a lot of moving parts,
9 and we really appreciate all the work that the State Water
10 Board done and all the agencies here today. So if and
11 when we see the policy and comes out and it's, you know,
12 well supported with a lot of facts and there's deadlines
13 in there that are supportive for why it's going to help
14 grid reliability and also, you know, end the killing of
15 these marine species as soon as possible, then that's, you
16 know, something that we're going to support.

17 DR. JASKE: Mr. Powers?

18 MR. POWERS: Just a couple of comments. One is
19 the two nuclear plants that use two-thirds are the once-
20 through cooling water along the coast, and we do have one
21 plant in the United States, a nuclear plant, that was
22 retrofit from once-through cooling to cooling towers
23 effectively -- cost effectively at less than \$70 a kW in
24 1999 dollars.

25 And as I mentioned earlier, Diablo Canyon and

1 SONGS are already conducting more costly and much more
2 invasive retrofits of their core systems and doing it
3 effectively and doing it very quickly. And that the
4 nuclear plants must be front and center in the discussion
5 about the cooling tower conversions.

6 And I think that the comments that have already
7 been made about the boilers that if the state is not
8 identifying the once-through boilers as under resource
9 adequacy contracts or under some concrete mechanism that
10 tells us that these plants are really necessary, then they
11 should compete. And if they cannot compete, they can
12 shutdown. And if they are necessary, they can be
13 retrofitted very cost effectively relative to new capacity
14 with cooling towers.

15 DR. JASKE: All right.

16 COMMISSIONER BYRON: All right. Thank you,
17 Dr. Jaske. Thank you very much, panelists. I hope you'll
18 stick around for the public comment as well.

19 MS. KOROSK: Commissioner Byron, we do have a
20 couple of questions from the web.

21 COMMISSIONER BYRON: Okay.

22 MS. KOROSK: And they're just strictly on this
23 panel.

24 COMMISSIONER BYRON: Please.

25 MS. KOROSK: We should do that before the

1 panelists leave. So from Chris Williamson, we have at
2 what point are the concerns of local government taken into
3 account related the continued use of OTC plants and their
4 jurisdictions and the Coastal Commission? Oxnard has two
5 OTC plants and SCE is now adding a peaker plant and would
6 like to consider the eventual removal of the OTC plants.

7 COMMISSIONER BYRON: They are to answer that
8 from our panel?

9 MS. SIVAS: Well, it's probably better answered
10 by some of the agency folks. I mean I would just say that
11 there is -- there is a process, as we heard this morning,
12 where the Coastal Commission and the Energy Commission
13 work in cooperation and also look at local land use
14 issues. And I think it was mentioned here today that
15 Morro Bay is an example where the city was involved as
16 well. But I'm obviously not the expert.

17 MS. KOROSSEC: The next question we have was from
18 Eric Miller. We've heard about PM10 issues and occasional
19 references to CO2 emissions. Given the increase in
20 emissions that would occur with the transmission away from
21 OTC to alternative cooling, how can we reconcile these
22 increases with the both the goals the AB 32 and the ever
23 increasing body of literature linking CO2 emissions,
24 climate change, and global declines in marine resources,
25 which have all outweighed any effects of OTC?

1 Examinations of long-term data studies in the
2 Hudson River, Chesapeake Bay, as well as Southern
3 California have declines in marine resources largely
4 linked to climate change and associated oceanographic
5 coursing. How do we as a state reconcile the desire to
6 end OTC with the potential to increase global stress on
7 marine communities further exacerbating the current
8 problems marine resources face?

9 MR. POWERS: I can answer that. I think the
10 question is if you retrofit a coastal boiler from OTC to a
11 cooling tower are you going to be having a significant
12 impact on greenhouse gases and climate change. And my
13 response to that would be I consider that if you --
14 cooling tower retrofit may impose one percent to one and a
15 half percent efficiency penalty on these units if they're
16 operating five percent per year.

17 The amount of additional air pollution that will
18 be emitted will be a fraction of any major source trigger
19 level in any of the district where they're located. And
20 so my perspective on -- Yes, there will a very small
21 ancillary increase in emissions, but the benefit of
22 eliminating the once-through cooling is of greater benefit
23 than that arguably de minimis increase.

24 MS. KOROSK: For Ms. Haren and Ms. Sivas, you
25 mentioned that the air emission question is not a

1 significant concern, but at a recent January '09 US
2 Wildlife Service/US Geologic Service meeting on climate
3 change and the West Coast Marine Resources painted a grime
4 picture relating to CO2 emissions and that they're growing
5 faster than the IPCC worst-case scenario of ocean
6 acidification, biogeographic shifts, sea level risk, and
7 other climatic issues based on recent research. In the
8 most recent research, it indicates climate changes
9 accelerating beyond the IPCC worst-case scenario due to
10 CO2 emissions. Would you still say that these emissions
11 are not a significant concern for marine resources?

12 Representatives of the West Coast Governor's
13 Agreement on Ocean Health distributed questionnaires
14 asking for ways to integrate all climate changes and all
15 marine regulations analyses due to its importance.

16 MS. SIVAS: So I'll just start and just a point
17 of clarification. I hope I didn't say it and I didn't to
18 say that emissions were not a significant problem, both
19 PM10 emissions for local populations in the South Coast
20 and elsewhere and also obviously greenhouse emissions.

21 I think what I was trying to say is I'm hoping
22 that those issues, which having grown up in the South
23 Coast years and years ago now, it was a problem even then,
24 and the hope is that all of the wise minds that have
25 gotten together in this room and elsewhere work that out.

1 My point was merely that the resolution of those issues
2 should not drive the policy throughout the state on once-
3 through cooling, and maybe that through a grid reliability
4 approach to the problem, we start with other areas of the
5 state as the South Coast issue gets worked out. So I hope
6 no one took that to mean that they're not significant air
7 emissions. They're obviously quite significant.

8 MS. HAREN: It's also addressed to me. I also
9 never meant to imply that it wasn't a significant issue.
10 Obviously, it is. We are concerned about global warming
11 and the impact on the marine environment as well as
12 everything else.

13 I also was answering a specific question that
14 was posed about tradeoffs. And our belief is that there
15 don't have to be tradeoffs, that we can both enforce the
16 Clean Air Act and the Clean Water Act. And that, in fact,
17 because of many of these plants are older and less
18 efficient and have higher greenhouse gas emissions rates
19 that some newer generation, that it's our hope that
20 solving the once-through cooling issue will also give
21 benefit to reducing some greenhouse gas emissions.

22 MR. POWERS: A point on the PM10 issue. Just as
23 a practical regulatory matter, San Diego County APCD,
24 South Coast, Ventura, and Bay Area, the cooling tower
25 permitting in those districts are exempt from permitting

1 requirements. And at least from an administrative
2 standpoint, the cooling towers can move forward on that
3 basis.

4 One of the generator commentators mentioned that
5 they couldn't put a wet tower at Moss Landing because the
6 district would have required PM offsets. Those PM offsets
7 are readily available through road paving. Both Morro Bay
8 APCD and San Luis Obispo APCD where Diablo Canyon is
9 located allow low-cost road paving to offset emissions
10 from the facility and indicated that that would be allowed
11 in the case of retrofits at either of those facilities as
12 well.

13 COMMISSIONER BYRON: Get those cars to stop
14 driving on those roads. All right. Ms. Korosec, you have
15 some additional public comments. Can you give us an idea
16 of how many you have there?

17 MS. KOROSEC: I have two cards only.

18 COMMISSIONER BYRON: Okay. That does not limit
19 anyone else that wishes to speak.

20 MS. KOROSEC: I see there's two other hands
21 going up out there.

22 COMMISSIONER BYRON: You can probably assume
23 there will be a few more.

24 MS. KOROSEC: I would imagine. So the first
25 card is from Mark Turner, Vice President of Competitive

1 Power Ventures. Second is from Rory Cox, Pacific
2 Environment. I guess we lost Mr. Cox.

3 MR. COX: No.

4 MS. KOROSEC: Go ahead and come up to the podium
5 if you wouldn't mind so you can get it on the record.

6 MR. COX: Thanks a lot for considering this
7 highly complex issue.

8 COMMISSIONER BYRON: Please identify.

9 MR. COX: My name is Rory Cox. I'm the
10 California Program Director at Pacific Environment. And I
11 did just want to reiterate what Mr. Powers mentioned about
12 the Chula Vista proposed decision and the historic
13 implications of that in terms of the viability of PV solar
14 to replace peaking generation. I think that's -- I think
15 that's our future. I think that's the future of this
16 discussion, and I've heard very little about it today. I
17 think in the past there wasn't even a meeting when the
18 word solar was ever uttered, and I think that's
19 overlooking a huge solution to --

20 COMMISSIONER BYRON: All right. We'll start
21 every meeting from now on right after the Pledge of
22 Allegiance we'll say solar.

23 MR. COX: Thank you. And also in terms when
24 we're talking about costs, you know we don't talk about
25 costs of asthma and the public health costs. And what I

1 heard a lot of was trying to, you know, get around the air
2 pollution laws in the South Coast region by, you know,
3 getting more permits, and I think there's a human level
4 that was just missing from the discussion and those costs
5 of public health on building more power plants. And we
6 need to add that into the discussion.

7 The cost of global warming, you know, Nicholas
8 Stern put out his groundbreaking study that demonstrated
9 that was going to take a huge hit out of the world's
10 economy if it goes unchecked. And that's the case whether
11 the power plant is -- whatever kind of power plant it is.
12 If it's fossils, it's going to cause global warming.

13 Another thing I just wanted to point out was the
14 PUC's report on the 33 RPS goal. The only way we can meet
15 that is no new fossil generation, and that came from the
16 California Public Utilities Commission. So all of these
17 problems that we are facing there are solutions that I
18 think aren't being discussed enough. And I didn't really
19 hear a lot about it until the last panel. Again, I think
20 we need to put that in the mix a little bit more, so thank
21 you very much.

22 COMMISSIONER BYRON: Thank you, Mr. Cox.

23 MS. KOROSK: We have Steven Kelly, Independent
24 Energy Producers Association.

25 MR. KELLY: Thank you. This is Steven Kelly

1 with the Independent Energy Producers Association, and
2 this is kind of a follow up because I do have some things
3 to say about renewables and solar. As you know, IEP
4 represents a number of different types of technologies in
5 California, all the renewable technologies, as well as
6 gas-fired generation, so we have kind of this what I hope
7 to think is a more contemporary perspective about the
8 ability to build generation in California.

9 And I'd like to speak about this issue of
10 reliability, following up on Mr. Mansour's comments, and
11 renewables as a replacement, particularly the replacement
12 as I've heard discussed for possibly 19,000 megawatts of
13 gas-fired generation that's in load center. And I want to
14 put this in a little bit of context first, and most
15 agencies are pretty much working on a 2020 context, the
16 GHG goals are supposed to be, the RPS 33 percent goals is
17 supposed to be couched in terms of 2020.

18 I just want to remind this Commission and I'm
19 pretty certain you haven't forgot this that that's 12
20 years out. We've been running an RPS in California for
21 eight years now, and we've gotten 800 megawatts of
22 installed renewables, so the track record for renewables
23 to not only meet new demand but replace the existing
24 infrastructure is not very good.

25 And as I look forward and look out over the

1 horizon as I work on the RPS statewide at the PUC and
2 elsewhere, I don't think the track record is posing a very
3 good solution. As you all know wind, geothermal, biomass,
4 solar thermal, all are difficult to construct in
5 California, not only the permitting and siting of those
6 facilities, but particularly getting the transmission in
7 place. Most utilities will admit or say that it takes
8 seven to ten years to build transmission that will link
9 into the renewables that would be this replacement
10 technology for the kinds of resources that are supporting
11 the system today. Biomass you can't even get to, so I
12 don't think there's any prospect that that resource is
13 going to be a significant replacement for the existing
14 status quo.

15 I've heard it said that solar photovoltaic is
16 going to be the solution. When I look at photovoltaics,
17 and I've got members that are developing photovoltaics so
18 we support this as a technology, I notice a couple of
19 things. One, it's about \$20,000 to install on rooftops.
20 I think the public sector is subsidizing that about 50
21 percent. The cost to replace the 19,000 megawatts of
22 generation that's being provided through these facilities
23 we're talking about today is tremendous. We've done a
24 calculation for rooftop PV, and the cost for that on a
25 cent per kilowatt hour basis is anywhere from 25 to 40

1 cents a kilowatt hour.

2 We support this technology and we think it's
3 something that's important for California, but the
4 expectation that that this technology is going to be able
5 to replace these other existing generation technologies is
6 what I think very faulty assumptions particularly in the
7 short term over the next ten to twelve years. The cost of
8 doing it and the implementation impediments for doing it
9 on homes is probably far too great to work on an
10 assumption that it will be there when these existing
11 generators are removed from their locations.

12 It speaks for the recognition that we really
13 need a transitional program. Certainly, one that looks
14 out at five to ten years and possibly more. We need to
15 make sure from a reliability perspective that the lights
16 stay on, that we have a mechanism to incent not only the
17 new technology that the state wants, the renewables, but
18 we can't do that in an environment where the lights -- we
19 have grid reliability problems.

20 So I would recommend that we look at this as a
21 program, a fix that needs to get in place, and
22 transitional mechanism to do this with the expectation
23 that perhaps we'll make a 33 percent RPS goal by 2020.
24 I'll just observe that right now we've got a 20 percent by
25 2010, and we're probably at least three years behind on

1 that goal, so we have a lot of work to do in the renewable
2 world.

3 And the assumption that that is going to be the
4 technology that is going to be there to solve the problems
5 in the near term is not one that I think is well grounded
6 in the facts of installation. So those are my comments.

7 COMMISSIONER BYRON: Very good.

8 MR. KELLY: Thank you.

9 COMMISSIONER BYRON: Thank you.

10 MS. KOROSSEC: Do we have anyone else in the room
11 who would like to speak? If not, let's go ahead and open
12 up the phone lines. All right, the lines are open. If
13 there's anyone on a call that would like to comment,
14 please go ahead. Well, I'm not hearing anything unless
15 somebody is having a hard time getting onto the phone.
16 All right. I think that's -- We have no further public
17 comment.

18 COMMISSIONER BYRON: Okay. I note that we're
19 going to do -- we have Mr. Jaske down with some wrap-up
20 comments; is that correct?

21 MS. KOROSSEC: Correct, yes.

22 COMMISSIONER BYRON: So we'll finish with that.
23 But before we do, I'd like to turn to the follow members
24 on the Dais and ask if they have any final comments they'd
25 like to make about what they heard today.

1 MR. ST. MARIE: Thank you, no. This has been
2 very helpful. I will be briefing Commission Bohn about
3 this and we will have subsequent discussions, and we will
4 be back for more.

5 MR. MANSOUR: Again, thank you very much,
6 Commissioner, for organizing it the Commissioner's staff
7 that has been also very helpful in a lot of ways.

8 One key point that I think that we got out of it
9 I hope that we follow on it is involving the industry in
10 the debate, not just the debate, but in getting the
11 solution as well. From what we heard today is that
12 they're not necessarily -- it's not necessarily that they
13 just own facilities that's been the source of the issue,
14 but they're also willing to be part from the solution, and
15 I think we should follow on that offer.

16 Obviously, we were, at least the agencies in the
17 ISO, were counting on some sort of incentives in the
18 procurement process to at least encourage within reason
19 the repowering of the existing OTCs, and I did not get a
20 lot of ideas on how that can be achieved. But I think
21 there's movement in the industry including the generators
22 and load serving entities will be very helpful to get us
23 to some solution on that.

24 Two times I guess there was mention of a
25 reference to a study, a reliability study that was done

1 that was not by ISO with some representation of -- of
2 other results. I recall only two, and I hope we can also
3 include reference to anything else that was not -- that I
4 don't recall, so maybe we should refer to those, one of
5 them by the Energy Commission. I believe it was two years
6 ago or so. It was a study to find options to all the
7 plants to retire those plants. And the result of that
8 study that I recall said whatever you retire, you need to
9 replace it (inaudible). That was actually very kind of,
10 you know, great. (Inaudible) you read that conclusion.

11 And the second one was by the Water Board for
12 what was intended to be a reliability study that I read
13 the result of it was an analysis of the various locations.
14 And at the end, it said something to the effect that the
15 local reliability issue is a very complex one and we're
16 glad that the ISO is looking at it and not us. I mean the
17 entity that actually did the study. That was the second
18 one that I recall.

19 And there are others that actually gave
20 solutions to -- the solutions as to the reliability issue
21 that we would be more than happy to entertain. But the
22 reliability issue when you talk about the computations and
23 combinations of all of the facilities that we're looking
24 and which one can be done when and where do they move to,
25 and when they move to those other places in the state, how

1 do they connect to the grid? There's virtually almost an
2 infinite number of possibilities, and that is why we try
3 to put out some case like bookends as to what the impact
4 is, and then by all the suggestions that we'll try to
5 narrow it down to a manageable size, a manageable level of
6 things that we look at as we go ahead, you know, to try to
7 give the Water Board some helpful suggestions as to how
8 they can move forward.

9 Let me also reiterate that the ISO I can assure
10 you that we aren't saying that this is a good policy or
11 not good policy. We won't say that results are high or
12 low. We will just say what it will take to fix and that's
13 what we've been doing. So any data that we provide is
14 along the lines of we're trying to help with the state
15 policies to be committed, but we also will stand
16 correcting any numbers or any statement that really are
17 out (inaudible) misstates the facts. So with that, thank
18 you very much, Commissioner, and the same for all the
19 staff.

20 COMMISSIONER BYRON: Thank you. Thank you,
21 Mr. Mansour. In fact, thank you, both, very much for
22 being here. I guess we couldn't keep you away. We do a
23 workshop called Options for Maintaining Electric System
24 Reliability When Eliminating Once-Through Cooling Power
25 Plants. Talking about reliability or taking plants off

1 the system gets the attention of the ISO and the PUC.

2 And of course, this Commission, prior to my
3 joining it, has made recommendations in the past in
4 previous IEPRs to retire aging power plants. They're
5 inefficient. I hope I'm not disclosing my feeling about
6 these plants, but these boat anchors, these old dogs need
7 to be retired, but we can't do it simply just by shutting
8 them down because there are very strong linkages to other
9 issues in addition to water.

10 There's obviously the priority reserve
11 associated with air emissions in the South Coast and
12 reliability that I mentioned earlier, so it's -- I think
13 someone said this earlier today that it's one of the many
14 issues and impacts on the environment, once-through
15 cooling that is, that we must balance in the decisions
16 that we make.

17 So it's extremely important to the work that
18 we're doing in the Integrated Energy Policy Report. That
19 was the original intention of this committee workshop
20 today and, of course, it's also linked very closely to the
21 rule that the State Water Resources Control Board will be
22 promulgating. I heard very clearly they're moving forward
23 on a fixed schedule and they expect the deadlines that we
24 propose in a plan to be met.

25 I can tell you that the agencies -- the energy

1 agencies are working very closely as part of the working
2 group on this issue that's been established in addition to
3 some of the other agencies that were represented here
4 today. This is a big problem, and we're going to have to
5 all work together in solving it. I learned a great deal
6 from the participants of the various panels today, but we
7 also know that this is tied up in court.

8 I was troubled to hear the comments of one of
9 the last panelists that indicate that there may be more
10 litigation. I don't think that was a threat. I think it
11 was just the indication that if we don't do this right, if
12 things don't move along quickly enough for those that have
13 been waiting many years to see action, that we could see
14 more litigation. We need settlements. We need that stuff
15 to get out of the courts to help move forward on this
16 because right now we have a lose, lose situation that's
17 affecting public health in a very serious way and will be
18 an impediment, notwithstanding Mr. Kelly's comments about
19 how slowly we're moving on our renewable portfolio
20 standards, but if we are not able to provide the kind of
21 resources that we need to firm up renewables going
22 forward, we're not going to be able to move forward in
23 that regard either.

24 So we need to fix this problem. This agency is
25 committed, too, and I know having met numerous times with

1 my colleagues at the ISO and the PUC and also having met
2 recently with a number of members of the State Water
3 Resources Control Board and staff, people in this
4 government are very committed to working on solving this
5 and providing a reliability based approach so that we keep
6 the lights but that we get this problem addressed in a
7 timely manner.

8 So I certainly welcome the participants of --
9 all the participants here today. The panels were very
10 good and very informative. You've all been very patient
11 sitting through all of this. I think the staff did a very
12 good job. I think we're going to end with some comments
13 from Dr. Jaske. I ask him as kind of our in-house expert
14 on this subject, and he's really been spearheading the
15 working group to make closing comments that I think that
16 we might all benefit from. Dr. Jaske, don't let me down.

17 DR. JASKE: I'll take about three minutes.
18 Several times I sort of hoisted up the March 2008 proposal
19 of the Water Board's scoping plan of 2015 for the low
20 capacity factor plants as a rather unrealistic way to go
21 about the problem. It doesn't really address the myriad
22 of nuances that we heard about today. And I only did that
23 because I know that Mr. Bishop is already convinced that
24 that's not the right way to go, and our collaboration up
25 to this point has given him a sense that we're going to

1 try to deliver a serious implementation proposal to them
2 very shortly.

3 He wants to publish his actual policy at the end
4 of June or early July, and it will contain some version of
5 our proposal, and we'll be able to put some of those
6 specifics on the table that people were asking for and
7 talk about it in some detail at the July 9th workshop
8 provided his timing allows that. We don't want to steal
9 his thunder, but we do want to provide an opportunity for
10 the energy industry to dive into the details.

11 I think we did hear some sayings that caused to
12 need to think at least here and there about our proposal.
13 Clearly, the generator community is saying they can do
14 some things that don't imply retiring all these plants.
15 There may be at least some of them that are worth
16 salvaging and some OTC reduction if not complete
17 mitigation could be done in conjunction with preserving
18 their life for another decade or so and maybe those
19 options, you know, need to be examined. They may well be
20 very specific to individual facilities. And so how to
21 bring that perspective to bear in developing our plan in a
22 sense, not in a sense, necessitates the cooperation of the
23 facility owners in sort of making that kind of information
24 known to us than just their oral statement today.

25 Clearly, the IOUs indicated there's ways in

1 which there are those processes that can be modified.
2 They're leaning toward the PUC in effect to figure out a
3 means by which they take OTC mitigation into account in
4 their selection of plants. And Bob Strauss made very
5 clear that that's coming and maybe it will come earlier
6 for the PG and E and San Diego areas where it's more clear
7 cut than for Edison where everyone seems to agree that
8 because of the South Coast air quality issues that at
9 least is lagging behind the other two areas in time and
10 probably ultimately in the tradeoffs between repowering
11 existing facilities and trying to rely upon other
12 technology to the maximum extent possible.

13 There's some push to act with this. Well, I
14 shouldn't, as is frequently the case when we're talking
15 among this community right here, we don't want to neglect
16 the fact that LADWP is in a different situation. And we
17 explored a little bit with Mr. Tharp the issues of their
18 system and how their system has evolved over time and
19 their own local reliability constraints. The Energy
20 Commission staff will be pursuing those details with LADWP
21 as quickly as we can.

22 We did hear that the Jones and Stokes
23 Reliability Study, you know, needs to be paid attention
24 to. And if it is flawed, the flaws need be expressed by
25 the energy agencies so that that environmental community

1 doesn't continue to rely upon it as a source of
2 information if it is, in fact, not supported by our views.

3 And we heard perhaps more than anyone else
4 Ms. Sivas say, my words summarizing her point, we need an
5 OTC policy stake in the ground and some milestones so that
6 everyone gets the message that that's the ultimate goal
7 and can get on with the very complicated work of trying to
8 figure out how to actually achieve that. But absent that
9 stake in the ground, everyone keeps waffling back and
10 forth about where we are going and when.

11 And I'll just observe lastly that, as seems to
12 always be the case, we had gigantically wide views about
13 the nuclear plants, their roles, the cost to do refit,
14 etcetera. And something more basic and fundamental
15 appears to be necessary to produce a compilation of
16 existing studies or reconcile the studies or do new
17 studies that sort of brings a more universally agreed set
18 of facts to the table.

19 COMMISSIONER BYRON: Thank you, Dr. Jaske. This
20 issue will be taken up at the State Water Resource Control
21 Board. We'll be taking it up again on July 9th here in a
22 workshop. Again, thank you for being here. We'll be
23 adjourned.

24 (Whereupon, at 4:35 p.m. the workshop adjourned)

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I, MARY CLARK, a certified electronic reporter,
do hereby certify that I am a disinterested person herein;
that I recorded the foregoing California Energy Commission
Workshop, dated May 11, 2009; that it was thereafter
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I further certify that I am not of counsel or
attorney for any of the parties to said meeting, nor in
any way interested in the outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand
this 26th day of May, 2009.



MARY CLARK, CERT*D-214

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