



COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, IEPR Committee

ADVISORS PRESENT

Laurie ten Hope, Advisor, Presiding Member Jeffrey D. Bryon

Susan Brown, Advisor, Vice Chair James D. Boyd

STAFF PRESENT:

Suzanne Korosec, IEPR Lead

Pam Doughman

Karen Griffin

Mike Magaletti

Al Alvarado

Angela Tanghetti

ALSO PRESENT:

At Dais

Robert Kinosian, California Public Utilities Commission

Panelists

Mark Minick, Southern California Edison

Antonio Alvarez, Pacific Gas & Electric

Ryan Pletka, Black and Veatch

Nancy Ryan, CPUC

Jaclyn Marks, CPUC

Dave Hawkins, CA ISO

Geoffrey Brand, ICF International

ALSO PRESENT

Panelists (Cont.)

Steven Kelly, Independent Energy Producers

Carl Zichella, Sierra Club

Darius Shirmohammadi, California Wind Energy Association

Danielle Osborn Mills, Center for Energy Efficiency and  
Renewable Technologies

Jeffrey Hahn, Covent Energy

Martha Davis, Inland Empire Utilities Agency

PUBLIC COMMENT

Jack Ellis, Resoro Consulting

Gregory Blue, SimPower Corporation

Merwin Brown, PhD, University of California,  
California Institute for Energy and the Environment

Arthur O'Donnell, Center for Research Solutions

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

2 9:06 A.M.

3 MS. KOROSSEC: I'm Suzanne Korosec. Welcome to today's  
4 Joint Committee Workshop on the electricity system  
5 implications of achieving the goal of 33 percent of our  
6 electricity coming from renewable resources.

7 This workshop is being held jointly under the Energy  
8 Commission's Integrated Energy Policy Report Committee and  
9 the Renewables Committee.

10 I believe that Commissioner Levin, from the Renewables  
11 Committee, intends to join by phone at some point today so  
12 we'll keep an ear out for her.

13 Just a few housekeeping items before we get started.  
14 Restrooms are out in the atrium, through the double doors  
15 and to your left.

16 There's a snack room on the second floor, at the top of  
17 the stairs, under the white awning.

18 And if there's an emergency and we need to evacuate the  
19 building, please follow the staff out to the park that's  
20 diagonal to the building and wait there until we're told  
21 it's safe to return.

22 Today's workshop is being broadcast through our WebEx  
23 conferencing system. Parties should be aware that we are  
24 recording the workshop. I will make the recording available  
25 on our website immediately after the workshop and then we'll

1 also provide a written transcript, once that becomes  
2 available, which is usually about two weeks after the  
3 workshop date.

4 For speakers and commenters today, please be sure to  
5 speak directly into the microphone so that the people on the  
6 WebEx will be able to hear you clearly.

7 We have three panels scheduled for today, with Q&A and  
8 public comments after each panel. During the Q&A and public  
9 comment periods we'll hear from the folks here in the room,  
10 first, and then we'll open the WebEx phone lines to give  
11 parties listening in an opportunity to speak.

12 Our WebEx participants should let the WebEx coordinator  
13 know that you have a question so that we can queue up all  
14 the questions and make sure we give everybody on line an  
15 opportunity to talk.

16 And for parties in the room that wish to speak, you can  
17 either fill out a blue card, which are out on the table in  
18 the foyer and hand those to me, or you can just come up to  
19 the mike during the public comment period.

20 Please give the court reporter your business card when  
21 you're done speaking so we can make sure that your name and  
22 affiliation are spelled correctly in our transcript.

23 We're also asking for written comments for this  
24 workshop and those are due by 5:00 p.m. on July 16<sup>th</sup>.

25 This workshop's being held as part of the 2009

1 Integrated Energy Policy Report, or IEPR proceeding.

2 The Energy Commission prepares an IEPR, required to by  
3 statute every two years, that looks at trends in  
4 California's energy markets and makes policy recommendations  
5 to help make the State meet its energy-related goals,  
6 including the goal of reaching 33 percent renewables by  
7 2020.

8 The purpose of today's workshop is really to get input  
9 on what's needed for us to integrate these higher levels of  
10 renewables into the system.

11 California's renewable portfolio standard of 20 percent  
12 by 2010 was established in 2002, and the topic of even  
13 higher levels of renewables has come up in our IEPR since  
14 the first IEPR was published in 2003.

15 In that document we said it was important to develop  
16 ambitious longer-term goals for the post-2010 period, and we  
17 followed up on that in the 2004, 2005, and 2006 IEPRs,  
18 pushing the need for higher targets, discussing some of the  
19 major barriers to meeting our RPS goals, and identifying  
20 long-term strategies to help the State reach that goal.

21 In the 2007 IEPR we acknowledge that the State needs to  
22 make key changes in our State energy policy and our  
23 electricity system to make the 33 percent target feasible.

24 And in the 2008 IEPR we began the analysis of what it  
25 would take for the system to be able to support that level



1 of renewables. And we also committed to continuing that  
2 discussion in the 2009 IEPR, which is why we're here today.

3 One of the primary recommendations in the 2008 IEPR was  
4 to evaluate new fossil generation that may be needed to  
5 support a 33 percent target, taking into account concerns  
6 with the use of once through cooling and power plants, the  
7 need to address aging power plant retirements, and potential  
8 changes on how existing plants might be operating as a  
9 result of greenhouse gas emission regulations.

10 As part of this workshop the staff prepared a report in  
11 response to the IEPR Committee's direction in the scoping  
12 order for the 2009 IEPR, which called for an assessment of  
13 the interaction between renewable and conventional  
14 resources, including the amount, location, and performance  
15 characteristics of fossil generation that might be needed to  
16 firm up higher levels of renewables.

17 That report is available on the table out in the lobby.

18 The 2008 IEPR update also identified the need to  
19 coordinate with other studies being done on this topic by  
20 the California Public Utilities Commission, the Renewable  
21 Energy Transmission Initiative, the California Dependent  
22 System Operator, and others, and we'll hear a little bit  
23 more about those studies during our panel discussions today.

24 And so with that I will turn it over to the  
25 Commissioners for any comments.

1 COMMISSIONER BYRON: Well, maybe only one Commissioner.  
2 But I'd like to welcome everyone. My name is Jeff Byron and  
3 I Chair the Integrated Energy Policy Report Committee.

4 This is a joint committee workshop with the Renewables  
5 Committee. And I understand Commissioner Levin may be  
6 joining us by phone and if she is online, I'd welcome her  
7 comments.

8 I don't know exactly how we're set up technically, if  
9 she does call in; will her line remain open or will she be  
10 on WebEx.

11 MS. KOROSEC: She'll be on WebEx and once we know that  
12 it's her, we'll be able to open her line and leave her open  
13 throughout the day.

14 COMMISSIONER BYRON: Excellent. Joining me here --  
15 unfortunately, we don't have the Associate Members of the  
16 two committees with us today. Commissioner Boyd is on a  
17 well-needed vacation and Chairman Douglas is preoccupied  
18 with other issues this morning. I don't know if she'll be  
19 joining us later or not.

20 However, I'd like to welcome with me here at the dais  
21 this morning, Robert Kinosian, Advisor to Commissioner Bohn,  
22 from the Public Utilities Commission; Susan Brown,  
23 Commissioner Boyd's Senior Advisor; and my advisor, Laurie  
24 ten Hope.

25 This is another important workshop in the IEPR process.

1 This is the one that I have to say that I've been looking  
2 forward to for some time. And we've got lots of good  
3 representation here by way of the Public Utilities  
4 Commission has a number of staff members here, and the  
5 Independent System Operators, as well. I'm very pleased to  
6 see that, including a number of other stakeholders.

7 There is a little bit of reluctance as we move towards  
8 higher level renewables on the part of many folks, maybe not  
9 spoken at all times. We know this is going to be very  
10 difficult. There is some concern that it may be very  
11 expensive.

12 And we welcome the analyses that have been done by the  
13 Independent System Operator last summer, the more recent one  
14 by the Public Utilities Commission. These kinds of reports  
15 can do nothing less than inform us and make us better  
16 prepared for the challenges that are ahead.

17 But this is the policy of the State and it's been the  
18 policy of this Commission for a number of years to move  
19 towards 33 percent, the Public Utilities Commission through  
20 our Energy Action Plan, and the Independent System Operator  
21 have all joined in on this policy goal.

22 As you know, the Governor's Office has issued an  
23 Executive Order in this regard and we fully anticipate that  
24 there will be legislation, in all likelihood enacted this  
25 year.

1 But how do we get there? Goal setting is not enough,  
2 this will be a challenge.

3 As I indicated, we have the benefit of other studies.  
4 Our staff has been spending a great deal of time and effort  
5 dealing with this issue as well.

6 So it's highly dependent upon a number of input  
7 assumptions, it's predicting the future; very difficult to  
8 do. There's so many variables at play here.

9 Just to list a few, the amount of incremental  
10 renewables that will be needed?

11 The starting point, what are the current renewables  
12 that are available and on system?

13 We can't really anticipate the technology develop, nor  
14 the cost of that accurately.

15 And, of course, the siting and permitting issues that  
16 will be associated with these large land use requirements  
17 for many of the renewables that we're currently looking at.

18 The other unknowns are the aging power plants, the  
19 once-through cooling power plants; will they be replaced,  
20 will they be repowered?

21 And then, of course, what will the regulations for AB  
22 32 look like and how will they be implemented in this  
23 sector?

24 There are more. But we know that there's a lot of  
25 variables and it's difficult to predict the future at best.

1       So we're going to explore some of those today. We'll  
2 drill down on some of these assumptions.

3       This Commission is very interested in the input that  
4 you are here to provide; and we will be making some  
5 recommendations going forward in our policy report for this  
6 year on the implementation of renewables.

7       I'll stop there and ask if any of my fellow members  
8 here at the dais have anything to add? Ms. Brown?

9       MS. BROWN: Yes, good morning, everyone. Commissioner  
10 Boyd regrets that he wasn't able to be here today, but asked  
11 me to make a couple of comments on his behalf.

12       First, he has a very keen interest in the role of the  
13 renewable portfolio standard, as he recognizes that it's a  
14 major measure in the Air Board scoping plan for achieving  
15 our State's climate change goals.

16       And second, he's extremely interested in this whole  
17 issue of integration of renewables with other demand side  
18 and supply side measures.

19       And in particular he's interested in how renewables can  
20 operate in concert with combining power projects, carbon  
21 catchment storage, firming with natural gas generation, and  
22 also the role that distributed generation can play in  
23 avoiding the need for major new transmission lines.

24       So I just wanted to make those comments on his behalf  
25 and I look forward to the discussion today.

1 COMMISSIONER BYRON: Very good, thank you, Ms. Brown.  
2 Mr. Kinosian?  
3 MR. KINOSIAN: Thank you. Unfortunately, Commissioner  
4 Bohn couldn't be here today. He also has a very keen  
5 interest in the topics that are going to be addressed here  
6 today. In particular, he thinks that it's critical that as  
7 we move ahead on the ambitious State goals that we do so in  
8 an informed manner and, hopefully, in an intelligent manner.  
9 And that it is very important that the policymakers,  
10 and not just the policymakers, but the ratepayers understand  
11 what the impacts of these policies are.  
12 Thank you.  
13 COMMISSIONER BYRON: Very good.  
14 Commissioner Levin, are you with us?  
15 MS. KOROSEC: It sounds like she's not on, yet, so  
16 we'll check periodically through the day. Perhaps as we go  
17 through each panel we'll check before we --  
18 COMMISSIONER BYRON: Yes, I think she's about eight or  
19 nine hours ahead of us.  
20 MS. KOROSEC: Yeah, I think so.  
21 COMMISSIONER BYRON: So if she does come online and you  
22 see her, please let me know.  
23 MS. KOROSEC: Well, unfortunately, with the call-in  
24 system it doesn't identify the person's name; it only  
25 identifies the users, so that's why we'll need to check

1     periodically.

2           COMMISSIONER BYRON:   All right.

3           MS. KOROSEC:   All right, thank you.

4           COMMISSIONER BYRON:   All right.   Well, let's proceed.

5     I note that the first person on our agenda is Ms. Griffin,  
6     the California Energy Commission, Introduction, "Electricity  
7     System Implications of 33 Percent Renewable Energy."

8           MS. GRIFFIN:   Good morning, Commissioners and fellow  
9     analysts.   It's kind of fun to be here, at a technical  
10    workshop, where we really will be working among ourselves to  
11    figure out what we can learn from all the work that has been  
12    done so far.

13          If we stop and think what is electricity system  
14    integration, it's kind of two things.   One of them is the  
15    attributes of the system.   And for people who have been in  
16    this as long as I have, and Dave here, and some of the rest  
17    of you all, it used to be we just kind of talked about  
18    energy and capacity, and losses.

19          And then as we sort of go along, local area reliability  
20    became more and more of an issue, so that moved up to be  
21    almost as it is now, an equal feature with the system.

22          And then there was this thing, ancillary services,  
23    which the guys in the back room kind of handled.   Well, as  
24    the system has gotten more sophisticated and we're adding  
25    many more kinds of resources and many more kinds of players,

1 these system support functions have become absolutely  
2 critical.

3 And so much of the work that we're talking about today  
4 is these kind of system support things. It's ramping, it's  
5 ride-through, Black start, all of the things that we need to  
6 make the system actually work in a way that is reliable,  
7 that's instant, that's cost effective.

8 But it's something else then, too, the electricity  
9 system is kind of a machine. It's a machine that has  
10 hundreds of people who are developing parts of it, each one  
11 motivated by their own interests, trying to make money, or  
12 serve the public purpose, whatever it is that they're trying  
13 to do.

14 And so we are trying to develop a system which  
15 coordinates and incents all of these people to work together  
16 to provide what it is that we want in terms of a physical  
17 system. So we need to always keep thinking of both of these  
18 things, physically what are the options and sort of socially  
19 how do we accomplish it.

20 What we're doing today is a metastudy; we're looking --  
21 which is a study of studies. We're looking at work that has  
22 been done, that's underway, and is about to launch out of  
23 the gate in terms of what can we learn from these studies.

24 Each one has its own framework; it has its own  
25 objectives and time. You might think that in an ideal sort



1 of world we'd finish one study, we'd learn from it, we'll  
2 move onto the others; but we're kind of in a hurry here and  
3 so each party is trying in their own way to figure out a  
4 piece of the problem.

5 So today, again, we're trying to learn what has each  
6 person learned, how can that enrich what we know.

7 Ideally, what we'd be figuring out is, obviously, what  
8 are the key issues that we want to address, what are the  
9 tools that we have, and what does each tool tell us so that  
10 we can use that tool for the appropriate way and not try and  
11 answer questions with inappropriate tools.

12 We're also trying to figure out which are the key  
13 drivers, which ones are the most important to deal with,  
14 which need to be addressed in which order.

15 Another thing we're trying to figure out today is what  
16 are the key uncertainties, and there are kind of two kind of  
17 uncertainties. There's the uncertainty that's really  
18 uncertain, you just don't know and you're never going to  
19 know.

20 So you're going to have to think about how you deal  
21 with the error band, trying to estimate how big your sort of  
22 level or risk here is on the level of uncertainty.

23 And then there are some other things which are  
24 currently uncertainties, but with analysis we can lessen the  
25 amount of uncertainty.

1           So to the extent that people have taken a piece of the  
2 puzzle, looked at it and said, okay, I think we know the  
3 answer now, or we know the parameters, or we know the  
4 direction that will really help us in this process.

5           I'm hoping that what we do today, as we talk about what  
6 do we know now that we didn't know a year ago, what are we  
7 going to know in six months that we don't know now, and what  
8 is it that we really don't know that we need to do some more  
9 work on.

10          And with that, I'm going to call the first panel. I'm  
11 not sure how many of them are here. Originally, we had  
12 four. I think we have two live bodies and one on the web.

13          So we have a representative from Southern California  
14 Edison. We have Ryan, from Black & Veatch, he's on the  
15 phone, going to be on the WebEx.

16          We haven't been able to get a hold of him, yet.

17          And we have Antonio Alvarez, from PG&E to talk about  
18 it.

19          And so if Mark, are you here, and Antonio, if you could  
20 come up and sit here, we'll get going.

21          COMMISSIONER BYRON: Gentlemen, weren't we just here  
22 recently on some panels?

23          MR. MINICK: Last week.

24          COMMISSIONER BYRON: I hope you got a weekend?

25          MR. MINICK: I did, actually.

1 COMMISSIONER BYRON: Thank you for being here.

2 MS. GRIFFIN: Let me borrow this for a minute. The  
3 purpose of this first panel, which is our studies which have  
4 been done, which is the Black & Veatch, is they're talking  
5 about the RETI Study, which is developing the renewable cost  
6 location transmission and environmental issues that much of  
7 the rest of the work is drawn from.

8 So a representative from Black & Veatch, who did a lot  
9 of the technical work for the first part of RETI provided  
10 information, provided a handout and some slides on that  
11 work, you know, what's available from it, the uncertainties  
12 and cost information that's available.

13 And he was also prepared to talk about the recent RETI  
14 2, in terms of how it was different from the first of the  
15 reports.

16 We also have a representative from PG&E, who's  
17 developing an exciting new tool to help us figure out  
18 integration issues in order to lessen some of the  
19 uncertainty.

20 So welcome, we're looking forward to hearing about  
21 that.

22 We have Edison is representing, I think several  
23 utilities funded your study?

24 MR. ALVAREZ: Yes.

25 MS. GRIFFIN: So you'll be talking about that.

1 And is Joe going to be on the phone, Joe Eto?

2 MS. DOUGHMAN: Yes, he was going to be listening in.

3 MS. GRIFFIN: Is Joe Eto on the phone?

4 The FERC has also commissioned a renewables integration  
5 study and the study is being done, at least in part, by LBL,  
6 and so Joe Eto was going to be available to give us a little  
7 bit of a perspective of what they're going to be doing in  
8 that study.

9 So I'd like to start with Antonio.

10 MR. ALVAREZ: Sure. I don't have a presentation, per  
11 se, but I'd like to just say a couple of words about what we  
12 were trying to do and open for questions.

13 Our approach, you know, is not necessarily a study in  
14 the sense that we're not trying to quantify what's the cost  
15 of going from 20 percent to 33 percent RPS.

16 Our focus was trying to understand the integration  
17 question of intermittent resources, so we were interested in  
18 finding out, you know, what is the ability of the system to  
19 integrate additional intermittent resources, what drives the  
20 need for flexible resources to integrate those resources,  
21 and what's the cost of integrating the resources.

22 So we're focused very much on one of the points that  
23 Karen raised at the beginning, you know, this ancillary  
24 service component.

25 And in our approach we're looking at ancillary services

1 in three buckets. We're looking at regulation, we're  
2 looking at load following, and we're looking at resources  
3 that need to be available for the commitment uncertainty.

4 So what drives the need for integration, just to say a  
5 couple of words, is the variability of the variable  
6 generation and the difficulty that we have with respect to  
7 the uncertainty, with respect to the generation, output that  
8 we expect for the next day or the next hour.

9 So to the extent there is -- we cannot predict the  
10 generation, that means that we have to have resources that  
11 are flexible enough to take whatever deficiency, or if there  
12 are than we expected in the head that they're able to reduce  
13 the output to accommodate the additional generation.

14 In doing our work and this is -- by the way, this  
15 is a joint effort that we had with the Brattle Group, we  
16 have developed a flexible tool that you can define the  
17 particular portfolio you're looking at, you know, how much  
18 intermittent generation you have, what type, what location,  
19 what's the variability, what's the forecast error of that  
20 generation.

21 And then look at it, then estimate the amount of  
22 integration resources that you need, the level of ancillary  
23 services that we need, and the fixed and variable cost of  
24 integration.

25 We don't look at transmission or look at the additional

1 cost of renewables, that's -- you know, other studies are  
2 doing that we thought that we probably added more value by  
3 looking at the integration question.

4 Let me just finish by saying that the current planning  
5 tools that we have are not looking at the integration  
6 question of the operational need issue, and so there is a  
7 need for developing new tools, developing a better  
8 understanding of those operational requirements, and also  
9 there is a need for better data with respect to what are the  
10 hourly profiles of intermittent generation, what's the  
11 forecast error of intermittent generation both for wind and  
12 solar, in particular.

13 So those are my opening comments and I'm happy to  
14 answer any questions.

15 MS. GRIFFIN: Are there questions from the dais?

16 COMMISSIONER BYRON: A quick question or two, just so I  
17 understand.

18 Did I understand you to say that the study you did  
19 doesn't include transmission cost or the additional cost of  
20 renewables?

21 MR. ALVAREZ: No, this is only focused on what are the  
22 operational needs for integrating intermittent generation.

23 COMMISSIONER BYRON: So what kind of technologies did  
24 you look at in terms of meeting the intermittency and, you  
25 know, the load quality and capability that you analyzed?

1           MR. ALVAREZ: Right. The tool is designed to provide a  
2 bench mark of what is the -- what are the needs for  
3 resources, in terms of amounts of conventional resources.

4           Now, we're looking at conventional resources just as a  
5 bench mark, in the sense that, for example, you're familiar  
6 with the market price reference, something that provides a  
7 point of reference for what are the needs of integration or  
8 the needs for flexible resources.

9           So it's all referenced to a conventional, flexible  
10 resources that are capable of integrating resources.

11          Now, after you have determined that amount and that  
12 cost you can look at different ways of providing that  
13 integration, having a reference point or bench mark.

14          COMMISSIONER BYRON: So I'm still not quite grasping --

15          MR. ALVAREZ: Okay.

16          COMMISSIONER BYRON: -- the scope of the study, because  
17 you did mention what you determined that cost; but that cost  
18 would be the MPR, the market price reference?

19          MR. ALVAREZ: No, I'm trying to make a parallel in this  
20 one. If you look at renewable resources, for example, the  
21 California Public Utilities Commission has adopted a market  
22 price recommend, which is basically the cost of conventional  
23 resources.

24          But what I'm saying is that in the same way we develop  
25 a tool that looks at integration based on the cost of

1 conventional resources that are used to integrate  
2 intermittent generation.

3 So additional ways of integrating intermittent  
4 generation is available, storage, perhaps demand response,  
5 and those can be looked at with respect to the bench mark  
6 that we've developed with the tool.

7 So once you have the amount, the cost of integration  
8 using conventional resources, then you can look at the  
9 alternatives for integration.

10 COMMISSIONER BYRON: So the -- when I asked earlier  
11 about the technologies you assumed then, it's primarily  
12 assuming that it would be a natural gas --

13 MR. ALVAREZ: Right.

14 COMMISSIONER BYRON: -- type of generation that would  
15 meet your --

16 MR. ALVAREZ: That would provide the integration,  
17 right, option.

18 COMMISSIONER BYRON: The regulation load following and  
19 day ahead kind of capability you're looking for.

20 MR. ALVAREZ: That's correct.

21 COMMISSIONER BYRON: Did you find, did the results  
22 surprise you?

23 MR. ALVAREZ: There was one interesting takeaway that  
24 we have, which is that there is a point in time, a point as  
25 you add more intermittent resources that where you have the



1 need for additional flexible resources that aren't provided,  
2 in excess of the reliability requirement of the system.

3 Today we look at reliability as expected peak plus an  
4 even planning reserve margin. We think that over time, as  
5 you add more intermittent resources, that you will need  
6 perhaps additional ancillary services that are not provided  
7 by the current planning reserve margin. That you will need  
8 to add flexible resources in excess of the current planning  
9 reserve margin.

10 So the need could be higher because you will have more  
11 flexible resources that are needed for integration.

12 The planning reserve margin, just to kind of review a  
13 few concepts, is intended to cover not only ancillary  
14 service, kind of basic operating reserves, but in addition  
15 to that you have to cover for forced outages, you have to  
16 cover for the increasing load as associated with warmer than  
17 normal summer temperatures.

18 So once you account for that, you have a limited amount  
19 of ancillary services. And there is a point, we think,  
20 where you may need additional ancillary services for  
21 integration.

22 Now, we plan to calibrate the tool, working with the  
23 ISO as part of the 33 percent integration study, so that  
24 we're able to better determine what is the ability of the  
25 existing system when you have, for example, 15 percent

1 planning reserve margin what can you integrate? What level  
2 of intermittent generation you can integrate, what type of  
3 resources you can integrate and up to what point with the  
4 current planning reserve margin.

5 COMMISSIONER BYRON: So I would -- just have two  
6 questions remaining. One is did you just look at your  
7 service territory or was this an effort to do some analysis  
8 on a statewide basis?

9 MR. ALVAREZ: Our purpose was to develop a tool that  
10 could be applied to basically any system. So we have done  
11 some test runs, which I included in the slides that are  
12 attached to my handout.

13 We looked at the ISO control area and we added  
14 increasing amounts of wind in the Tehachapi area, and we  
15 looked at what was the increasing regulation, increasing day  
16 ahead and load following requirements, and also estimated  
17 the integration cost.

18 We'd like to go back and, using the same kind of  
19 portfolio of intermittent resources that the ISO integration  
20 study is going to look at, and with that use the same  
21 scenarios, the same forecast errors that they're using, and  
22 compare the results with the results that the ISO will be  
23 getting.

24 COMMISSIONER BYRON: And this tool will be available  
25 publicly?

1           MR. ALVAREZ: Yes, we do plan to make the tool  
2 available. We're working with Brattle to make sure that  
3 we're able to handle all the questions and we have a good  
4 user manual, and documentation on the methodology.

5           COMMISSIONER BYRON: Thank you.

6           MS. GRIFFIN: I had a couple of questions from your  
7 slide stack, I want to make sure I understand it.

8           MR. ALVAREZ: Okay.

9           MS. GRIFFIN: It's a calculator, so it's a spreadsheet  
10 tool. The two examples that you gave, in terms of the  
11 uncertainty drivers, were load forecast error and wind  
12 forecast error. Are those examples or are those the only  
13 errors that you're looking at, forecast errors that you're  
14 looking at with this tool?

15          MR. ALVAREZ: We're looking at -- we're looking at the  
16 forecast error of load, again measured in three different  
17 time intervals, and we're looking at the forecast error of  
18 intermittent generation, whether it is wind, solar, or a  
19 combination of wind/solar.

20          So the user can enter the amount of generation,  
21 intermittent generation that you want to add, different  
22 locations. You have to work in getting the inputs, you  
23 know, the right hourly profile and have estimates for the  
24 forecast error, again, for three different time intervals.

25          And so you can -- just to answer your question

1 directly, we looked at the uncertainty of load forecast and  
2 the generation, uncertainty for intermittent generation.

3 MS. GRIFFIN: Okay, and that raised a question in my  
4 mind because we've had load forecasting error forever.

5 MR. ALVAREZ: Right.

6 MS. GRIFFIN: And so when I saw some of the slides  
7 which suggested that -- it's called a renewable integration  
8 calculator, and yet one of the chief drivers is load.

9 MR. ALVAREZ: Right.

10 MS. GRIFFIN: And that seemed like a little bit of  
11 loading on the back of renewables, something that has  
12 existed for all generation.

13 MR. ALVAREZ: Right.

14 MS. GRIFFIN: So is -- I guess is this an appropriate  
15 name for it or is there some particular element that you  
16 would have load forecast errors as one of the parts of this?

17 MR. ALVAREZ: Right. Let me explain why we did it this  
18 way. You have to look at the intersection between the load  
19 forecast error and the renewable integration forecast error,  
20 because there are some correlations -- or we need to account  
21 for the correlation between load and intermittent generation  
22 forecast.

23 Also, the weather drives both load and say wind and  
24 solar, so we want to look at them together.

25 Having said that, you can run the mull, you know, very

1 quickly by first adding the load and then adding increments  
2 of intermittent generation, and then you can estimate the  
3 incremental affect of say wind or solar added on top of the  
4 load forecast error.

5 So you can isolate the components of the say regulation  
6 or load following impacts that are associated with the  
7 increments of intermittent generation.

8 MS. GRIFFIN: Okay. And then on these two drivers, in  
9 terms of reducing the uncertainty, it would appear that over  
10 the past year and a half or so, two years, there's been a  
11 lot of progress on wind forecast improving, local hour ahead  
12 wind forecast; is that correct? So is that error band  
13 coming down?

14 MR. ALVAREZ: That's what I hear, yes.

15 MS. GRIFFIN: Okay. The paper didn't or the slides  
16 didn't really discuss sort of the source of the load  
17 forecast error part of this, you know, why is it as big as  
18 it is?

19 MR. ALVAREZ: Right.

20 MS. GRIFFIN: And are there things we can do to reduce  
21 that uncertainty, because these big uncertainty bands then  
22 suggest you need more ancillary services which then drives  
23 up the cost of everything. And, of course, in this economy  
24 everyone's very concerned about the costs of doing anything.

25 MR. ALVAREZ: Yes, right. Again, the forecast error is

1 a user input defined and so you can look at different  
2 scenarios. You know, look at for example in the future, if  
3 you anticipate a reduction in your errors, you can account  
4 for that in the tool.

5 The sources of the information that we have now is, for  
6 example, for the five-minute-ahead forecast error. We used  
7 information from the ISO's November 2007 integration work.  
8 We also had access to minute-by-minute generation and output  
9 that the ISO provided, so we looked at the variability  
10 within the five-minute interval of generation and load.

11 For the hour ahead and day ahead forecast errors, we  
12 used our experience in comparing day-ahead schedules against  
13 meter load and the same for wind.

14 So as you learn more about the uncertainty, you can  
15 update, you know, refine those estimates and adjust the  
16 results as well.

17 MS. GRIFFIN: Well, this then becomes a question for  
18 renewables integration; how important is it to focus on  
19 reducing load forecast error?

20 MR. ALVAREZ: Yeah, no, I think that's a very important  
21 area and I understand the ISO have been participating in  
22 some of the earlier work, trying to get a better handle on  
23 the forecast error. So that's definitely an area that needs  
24 to be worked on.

25 MS. GRIFFIN: And who does these forecasts; is it the

1 control area, the balancing authority, or is it the load-  
2 serving entities, such as PG&E?

3 MR. ALVAREZ: It's a mix of both. We do have our own,  
4 we do our own forecast for our wind. But I know the ISO has  
5 a program where they provide some of that forecast  
6 capability.

7 And I'm sure David Hawkins can speak about it more  
8 eloquently than I can.

9 MS. GRIFFIN: Okay, so we have usual mixed  
10 accountability here?

11 MR. ALVAREZ: That's right.

12 MS. GRIFFIN: Right.

13 MR. ALVAREZ: Right.

14 MS. GRIFFIN: Are there questions from the group?  
15 You're just going to have to come up.

16 And I'll remind everyone, for questions from the  
17 audience we need you at a microphone. Thank you.

18 MR. ELLIS: Hi, I'm Jack Ellis, from Resero Consulting,  
19 here on behalf of the Western Power Trading Forum.

20 Antonio, I notice that the only test case you've run so  
21 far looks at up to 8,000 megawatts of wind generation in the  
22 Tehachapi area.

23 Have you or are you considering looking at scenarios  
24 where there's a greater geographic dispersion of renewable  
25 resources and, if you have, what have the results told you?

1           MR. ALVAREZ: Yes, very much so. We have looked at  
2 both wind in different areas. We have looked at, for  
3 example, additional Bay Area wind, and also solar, both in  
4 the Mojave Desert and the southern part of our service area.

5           At this point I'm hesitant in talking too much about  
6 solar because we do not have a good estimate of the forecast  
7 uncertainty for solar, because we don't have much of an  
8 experience.

9           And so, you know, we have for initial runs, for  
10 example, assumed that the forecast error for solar is about  
11 a third of the forecast error for wind, just by looking the  
12 profile, the hourly profile and assuming that, you know, for  
13 example the current hour generation is the forecast for the  
14 next hour. So some simple -- simple assumptions like that.

15           But that's an area where I'd definitely like to have a  
16 little more information about the forecast of solar  
17 generation before I, you know, start showing those results.

18           MR. ELLIS: And I also wanted to clarify that at this  
19 point you've developed the tool and you're using new  
20 flexible generation as a proxy for all the measures that  
21 might be employed to either reduce the requirements for load  
22 following, and other ancillary services, or supply them?

23           MR. ALVAREZ: That's right.

24           MR. ELLIS: And then there would be some follow-on  
25 work --



1           MR. ALVAREZ: That's right.

2           MR. ELLIS: -- by either you, or the utilities, or the

3 ISO, or perhaps a combination of the two to look at those

4 options?

5           MR. ALVAREZ: Right.

6           MR. ELLIS: Okay, thank you.

7           MS. GRIFFIN: I had one more question. Are you

8 planning to introduce this tool at the PUC and the Planning

9 Reserve Margin proceeding, when that thing kicks back up

10 again?

11           You're -- one of your findings was you needed a higher

12 PRO and so --

13           MR. ALVAREZ: Yes, I think it will have to be

14 introduced somehow. I'm hesitant because I know that the

15 tool that so far has been used is a GE/MARS model, and MARS

16 uses -- basically assumes that whatever generation is there

17 is available, you know, kind of ignores the forecast error.

18           So what we're going to find, you know, the results that

19 we're going to find using the tool are going to ignore the

20 operating requirement. And so this will have to be kind of

21 layered somehow on top of that and trying to figure out

22 exactly how to do it at this point.

23           MS. GRIFFIN: Okay, but that's an important finding for

24 working on integration.

25           MR. ALVAREZ: That's right.

1 MS. GRIFFIN: Is that if the main tool that we're using  
2 in the planning area, which is the area I know, isn't  
3 adequately dealing with operational reliability, then we  
4 need to link together somehow.

5 MR. ALVAREZ: Yes.

6 MS. GRIFFIN: Okay.

7 MR. KELLY: This is Steven Kelly, with Independent  
8 Energy Producers Association. Hi, Antonio.

9 MR. ALVAREZ: Hi, Steven.

10 MR. KELLY: I'm looking at your presentation materials  
11 and I'm looking at the Tehachapi wind addition slide that  
12 begins on page 8 and 9, and I just wanted to make sure that  
13 I was reading this right.

14 If I understand, is there a -- how many megawatts are  
15 in Tehachapi today; about a thousand or something like that?

16 MR. ALVAREZ: Um --

17 MR. KELLY: Something, roughly? Roughly, yeah.

18 MR. ALVAREZ: Yeah.

19 MR. KELLY: So if I'm reading this graph correctly on  
20 page 8 and 9, if you doubled the amount of megawatts in  
21 Tehachapi, then the amount of regulation requirements go up  
22 to 20 megawatts? On page 8, is that the way that I should  
23 be looking at that?

24 MR. ALVAREZ: This is looking at incremental amounts,  
25 right.

1 MR. KELLY: Yeah, right, above --

2 MR. ALVAREZ: I'm starting from zero.

3 MR. KELLY: Okay.

4 MR. ALVAREZ: So if you add 2,000 megawatts over what

5 we have today, it would be about 20 megawatts more of

6 regulation.

7 MR. KELLY: And what does it take to provide that? I

8 mean, is that like a combustion unit or something that's one

9 50 megawatt gas-fired unit to do that?

10 MR. ALVAREZ: I would say it's a unit that can be on

11 automatic dispatch, that can basically have enough head room

12 that it can go up and down as a function of frequency.

13 So it could be a combined cycle, for example, that's

14 operating above the minimum generation.

15 MR. KELLY: And this would be just seeking another 20

16 megawatts from that unit to support the wind?

17 MR. ALVAREZ: Right, right.

18 MR. KELLY: And then on the load following the same

19 thing, I'm looking at page 9, just so I understand this; if

20 you went to basically 4,500 new megawatts of wind in

21 Tehachapi, the support for that would be a hundred

22 megawatt --

23 MR. ALVAREZ: Right.

24 MR. KELLY: -- load following characteristics would be

25 some sort of combined cycle?

1 MR. ALVAREZ: Yeah.

2 MR. KELLY: And would one combined cycle be able to  
3 provide both those services?

4 MR. ALVAREZ: Yes.

5 MR. KELLY: So we're looking at one unit to do both of  
6 that, to basically quadruple the amount of wind in  
7 Tehachapi?

8 MR. ALVAREZ: Right.

9 MR. KELLY: I just wanted to make sure I'm reading this  
10 correctly.

11 MR. ALVAREZ: Yes.

12 MR. KELLY: Okay, good. Thanks.

13 MR. ALVAREZ: I'd just like to point out, Steven, you  
14 know, as I mentioned before, we're calibrating the tool,  
15 making sure that we have all the right forecast errors, and  
16 the --

17 MR. KELLY: Sure. No, this is complicated stuff. So  
18 thanks.

19 MR. ALVAREZ: You're welcome.

20 MR. BLUE: Good morning, my name is Greg Blue with Sun  
21 Power.

22 MR. ALVAREZ: Good morning, Greg, how are you?

23 MR. BLUE: Hi you doing. Following up on Jack's, the  
24 first speaker's comment about some geographic diversity, and  
25 I know that WestConnect, which is a group of utilities in

1 the southwest are looking together at a AGC sharing type of  
2 an arrangement.

3 MR. ALVAREZ: Right.

4 MR. BLUE: Basically, expanding the geographic area of  
5 AGC.

6 MR. ALVAREZ: Right.

7 MR. BLUE: And is your model going to look at those  
8 kind of things beyond California?

9 MR. ALVAREZ: You can perhaps use the model. I mean, I  
10 haven't used it for that purpose. But to look at a greater  
11 area but, you know, for that purpose you will need to find  
12 all the things necessary to represent the greater area;  
13 load, load forecast errors, wind, all intermittent  
14 generation.

15 So I think it is possible to do.

16 MR. BLUE: All right.

17 MR. ALVAREZ: I'm not -- one thing that we don't do  
18 with the model is look at the local area constraints. We're  
19 assuming that there is ample transmission to be able to  
20 provide, you know, basically the regulation outside of the  
21 particular area where the intermittent generation is  
22 located.

23 MR. BLUE: Okay, great. And then Sun Power has a quite  
24 a few large-scale solar PV projects around the world and  
25 Europe --

1 MR. ALVAREZ: Right.

2 MR. BLUE: -- and we might have some -- I'm new to the  
3 company, but I'm pretty sure we would have some data --

4 MR. ALVAREZ: Great.

5 MR. BLUE: -- forecast data versus actual, that we  
6 could probably -- you know, some real experience.

7 MR. ALVAREZ: Yeah, I'd love to get it.

8 MR. BLUE: So I'll give you my card.

9 MR. ALVAREZ: Okay, thanks, Greg.

10 MS. GRIFFIN: And while we're changing speakers, we  
11 remind speakers to give a business card to the recording  
12 clerk, please. Thank you.

13 MR. BROWN: Hello, I'm Merwin Brown, with the  
14 California Institute for Energy and Environment. And I'm  
15 asking the question based upon your handout, because I don't  
16 think you addressed this in your remarks.

17 MR. ALVAREZ: Okay.

18 MR. BROWN: You had a statement on finding the  
19 conclusions that today's preferred resources, which are  
20 energy efficiency, demand response and distributed  
21 generation do not help integrate intermittent resources.  
22 That seems a fairly broad statement to make.

23 MR. ALVAREZ: Right.

24 MR. BROWN: And so I was curious, are there caveats on  
25 that, are there qualifications that you came to that

1 conclusion from this study; so could you elaborate, please?

2 MR. ALVAREZ: Nothing that came out from the study, per  
3 se, I'm just speaking from my familiarity with the  
4 existing --

5 COMMISSIONER BYRON: Mr. Alvarez, if you wouldn't mind,  
6 put the microphone in front of the direction you're speaking  
7 and it will help everybody to hear you.

8 MR. ALVAREZ: Right. Yeah, thank you.

9 I'm just speaking from my knowledge of the current  
10 demand response programs that we have. These are programs  
11 that are activated for a few hours in a year, 50, 100 hours  
12 per year, generally in response to a stress condition so it  
13 requires a half-hour notice.

14 So they're not quite designed to provide the flexible  
15 adjustments that are needed in generation, for integration  
16 of intermittent resources.

17 Not to say that in the future we couldn't design the  
18 programs and provide the technology to do that. We do have  
19 pilot programs that we are proposing in order to enable  
20 demand response to provide some of that.

21 MR. BROWN: Okay, thank you.

22 MR. ALVAREZ: Sure.

23 COMMISSIONER BYRON: Mr. Brown, thank you for bringing  
24 that up. I have to say when I read that finding or  
25 conclusion that today's preferred resources, meaning energy

1 efficiency, demand response, and distributed generation do  
2 not help integrate intermittent resources, it was very  
3 troubling.

4 I would say this is exactly the kind of conclusion we  
5 would hope that utilities would begin to move away from, as  
6 we've spent decades trying to implement these kinds of  
7 policies.

8 And to read that it doesn't do anything to help  
9 integrate intermittents is very troubling.

10 MR. ALVAREZ: But I mean we can discuss what are the  
11 operating features of these resources, and I hope that you  
12 understand the reason for that statement.

13 You know, we respect, for example, exterior generation.  
14 We generally think of exterior generation as baseload  
15 generation that has the utility -- or the California system  
16 operator has no control on that generation.

17 Therefore, if anything, it adds forecast uncertainty in  
18 the sense that if it is a customer-owned operating facility,  
19 we might have some variation in generation which would  
20 result in variation in load. So that adds to perhaps our  
21 forecast uncertainty on load.

22 Energy efficiency is generally not something that we're  
23 accustomed to think in terms of being able to change rapidly  
24 in response to load and those sorts of changes.

25 COMMISSIONER BYRON: Agreed.



1           MR. ALVAREZ: So that's the basis for my statement.  
2 Now, not that we can't think of different ways of  
3 implemented those preferred resources, but at this point  
4 that's the reality.

5           COMMISSIONER BYRON: Would it be different if the  
6 utility owned the distributed generation resources?

7           MR. ALVAREZ: I think it really is a function of what  
8 is the use of the resource? If the resource, for example,  
9 is intended to serve both, you know, taking exterior  
10 generation. A thermal user requires constant generation,  
11 constant heat for example.

12          If there is some flexibility in the generation I think,  
13 yes, definitely in the kind of byproduct of generation, I  
14 think there should be some flexibility.

15          I don't know if that's necessarily a function of  
16 whether the utility owns it or not. Perhaps there is a  
17 different way of thinking about exterior generation that  
18 even for a third party that could provide some of that  
19 flexibility.

20          But generally, you know, these are the -- these units  
21 are designed for baseload operation.

22          COMMISSIONER BYRON: Do we have any other -- I'm sorry,  
23 Ms. Griffin, this is your panel.

24          MS. GRIFFIN: Were there questions on the WebEx?

25          MS. DOUGHMAN: No.

1 MS. GRIFFIN: No. Okay, thank you. Let's move on to  
2 Mark.

3 MR. MINICK: Did you want me to describe the Nexant  
4 Study or answer the -- you'd previously given us questions,  
5 I could through and answer the questions?

6 MS. GRIFFIN: Right, I think you need to describe, in  
7 essence. Since we didn't have any written material from  
8 you, there was nothing that the audience could review  
9 beforehand.

10 MR. MINICK: Right. Okay, it's called the Nexant  
11 Study. In essence, Nexant was the contractor that we hired  
12 to do much of the work or the contractor for this particular  
13 study.

14 This study was undertaken by the three utilities, San  
15 Diego Gas and Electric, PG&E, and Edison. We're all joint  
16 participants financially in the project.

17 We also had some advice from the ISO during the course  
18 of the project.

19 It was started last year. The major purpose of the  
20 project was to take a look at expansion of renewables in the  
21 State of California. It was an entire State study, it  
22 wasn't just an Edison or an IOU study.

23 We, in essence, treated the entire State as a control  
24 area for the ISO. Which isn't exactly right, but where the  
25 biggest parts of California is the ISO, we thought it was

1 reasonable.

2 The purpose of the study was to look at integration  
3 needs for the study. How do we expand what shows up, what  
4 are the major issues that occur when you do a study like  
5 this and, of course, what are the costs?

6 The reason it's been somewhat under wraps is some of  
7 the cost information used by Nexant was confidential. And  
8 some of the other cost information we gleaned from other  
9 sources and we weren't sure how good it was.

10 I think we're at the point, now, where we can say it  
11 comes to very similar conclusions on a cost basis of the  
12 current E-3 study done for the PUC.

13 It didn't look at, we don't think, issues like that  
14 equivalents correctly, and some of those things because,  
15 again, Nexant isn't a utility and doesn't understand some of  
16 those.

17 The key was, is what did we find out and then what did  
18 we do?

19 Now, let me walk through sort of what we used. We  
20 tried to use public information to the extent that we could.  
21 So we used the TEPPC database last year, but we modified the  
22 TEPPC database, both PG&E and San Diego helped us clean up  
23 that database.

24 There were palms in that database about minimum loads,  
25 ramping times and things like that, that were in the

1 database that hadn't been cleaned up, yet. TEPPC has since  
2 cleaned up their database some, so it's a little better  
3 database.

4 We used the CEC load forecast of November 2007 as our  
5 basis. So in essence the State forecast, I think, was  
6 around 318,000 gigawatt hours of energy. It's probably gone  
7 down since, but that's what we used at the particular time.

8 We assumed 20 percent was our target. So the study  
9 basically assumed study years of 2012, 16, 2020, and 2025.  
10 It took a look at 20 percent in all those years and then it  
11 looked at, incrementally, how many more renewables that we  
12 have to add to get to 33 percent by 2020.

13 And we actually, because of the proposition on the  
14 ballot last year, looked at 50 percent by 2025. So in 2020,  
15 there was also a 40 percent.

16 I'll address most of my remarks here to the 33 percent  
17 case.

18 We did look at various scenarios. We looked at more  
19 wind scenario, more solar scenario, a 50/50 scenario. We  
20 did have to make inputs about gas prices. We used about  
21 \$7.50 a million BTU in 2008 dollars and 2008 escalating. As  
22 you know it's a little lower than that now, but we didn't  
23 last year, in July, anticipate the current recession as deep  
24 and as long as it is.

25 We also wanted to take a look at transmission

1 expansion. So the study wanted to take a look at is it  
2 feasible to build this many renewables this fast and if you  
3 could -- I mean, we hypothetically assumed 33 percent  
4 renewables by 2020.

5 And say okay, now, is it possible to get there and what  
6 does it take, and what are the ramifications of getting  
7 there?

8 So we built out the cases. Nexant looked at some data  
9 that they gave us, data for winds and solar at the time of  
10 our peaks, as well as hourly loads, so we synced it all to a  
11 common year.

12 We then used the Plexos production simulation model to  
13 do simulations of the entire systems under these various  
14 particular cases.

15 As Antonio said, intermittents will most likely raise  
16 the need for planning reserve margins. We don't know how  
17 much yet, Antonio and I are still studying it. It's a  
18 question we don't have an answer to, yet.

19 And other parties have worked with the PUC and their  
20 planning reserve margin studies.

21 For this particular study we didn't have time to do a  
22 study of planning reserve margins, so we locked in 18  
23 percent as a planning reserve margin target and built out to  
24 that particular level of 18 percent.

25 We found in a few cases 18 percent was inadequate to

1 meet what the model was saying was the ramping requirements  
2 for certain hours.

3 So this particular study did determine that we probably  
4 need higher reserves, we're not sure exactly how much yet.  
5 It depends on the mix of renewables. That has to be solved,  
6 yet, it's sort of a big issue.

7 So in some cases we actually had 21 percent reserves.  
8 Now, in that particular case we didn't add 21 percent  
9 reserves, we were using solar, more solar to meet the  
10 renewable targets.

11 And since solar produces most of its energy on peak and  
12 has quite a bit of capacity on peak, the apparent reserve  
13 margins for the planning purposes was 21 percent, simply to  
14 get more solar to make sure you get your 33 percent energy  
15 target. So it pushed you to that level to get that much  
16 energy.

17 For the purposes of planning we arbitrarily chose some  
18 capacity values for some of the renewables. In the resource  
19 adequacy accounting mechanism that the PUC has, you do count  
20 resources under a certain methodology.

21 We deviated slightly from that methodology. And  
22 everybody's going to ask how? We counted wind as ten  
23 percent capacity contribution, we counted solar in around  
24 the 55 to 65 percent range, it depends on the solar. Unless  
25 it had solar thermal with storage, meaning it had stored

1 enough energy in the morning that it could produce at full  
2 output at the time of the peak then it was more like 95  
3 percent.

4 For geothermal, biomass, and the like it was around 95  
5 percent.

6 So this is their capacity contribution towards the  
7 planning reserves.

8 The case that we centered most of our analysis around  
9 was sort of the 50/50 case. So if you took a look at that  
10 case in 2020, you'd find about equal amounts of solar and  
11 wind. Probably incrementally we added a little more solar,  
12 because right now we have a lot more wind than we have  
13 solar, and we built out the system and then ran it.

14 We did consider distributed generation. In this  
15 particular case we had to make assumptions about  
16 electrification, about distributed generation, about imports  
17 from other states, of renewable credits or renewable energy,  
18 either one.

19 To answer your questions about those, we had about  
20 2,700 megawatts, by 2020, of distributed generation. We had  
21 about six or eight hundred megawatts, I think, I'm not a  
22 hundred percent sure, of electrification for solar or for  
23 electric cars. It could be higher than that now, if we were  
24 to redo it.

25 We imported about 3,800 megawatts of either RECS or

1 imported power.

2 So we built the whole case out to run it and then came  
3 up with some findings and conclusions.

4 The findings and conclusions were interesting in the  
5 fact that they simply highlighted areas that we thought were  
6 going to show up in some cases, other things that we didn't  
7 know would show up in some cases, and outlined where we need  
8 to do a lot more research.

9 As you said, there are many, many things in here that  
10 are moving parts simultaneously.

11 We did make assumptions about retirement, about the  
12 unavailability of current once-through units. I can't say  
13 it's a necessarily prediction of retirements because we  
14 don't do that, but we had to take a look at the transmission  
15 grid because our grid's been built for the last 50 years.

16 If certain plants shut down and you build more remote  
17 or distributed generation, what does your grid look like and  
18 how does it affect the transmission system?

19 This study did take a couple of snapshots at the  
20 transmission system. It's not a robust analysis, like the  
21 ISO and like transmission planners usually do, but it did  
22 take a look at the peak hour, and let's say a springtime  
23 hour, about what is a transmission system doing, is it  
24 operable, does it flow?

25 We limited our imports to a certain amount from other



1 states.

2 So the bottom line is, is the model came up with an  
3 operable system, but it has some really interesting  
4 conclusions.

5 First off, operations became much more critical, and  
6 that's kind of why PG&E is looking at this real-time  
7 deviations of schedules.

8 We found that in certain instances we had to add some  
9 peaking resources, some quick start to give us enough  
10 ramping capability at certain times.

11 We found in the month of April we had the biggest over-  
12 generation issues to have to overcome.

13 For those to know our system, they know in April and  
14 May we have hydro runoff. They know the wind blows  
15 reasonably well, let's say, in April, May and June.

16 And that now, when you add solar on top of that, solar  
17 incidence in the Mojave Desert is quite high in even the  
18 month of April.

19 And so the loads on the State system aren't that high  
20 in April, and so we were running into on-peak over-  
21 generation issues in the month of April.

22 To solve this we need some kind of storage mechanism,  
23 because we have way too much energy coming from intermittent  
24 renewables and hydro at this particular time, so we really  
25 can't run the grid very well.

1           In the model we made the assumption that we'd use solar  
2 thermal storage. It doesn't matter whether it's solar  
3 thermal, or it's compressed air energy, or it's battery, or  
4 what, we need some kind of mechanism to store surplus energy  
5 in the month of April and May. Those are the months that  
6 causes the most trouble.

7           In July you can take all the solar output and use it  
8 because your loads are a lot higher. In April they're not  
9 and they're going to have over-generation issues.

10          We also developed the grid in a manner similar to what  
11 the RETI's looking at. So RETI has defined areas where  
12 there are more renewables that, from a pure economic stand  
13 point should develop first, all else being equal. And we're  
14 not a hundred percent sure where the renewables will  
15 develop.

16          So to be honest, Southern California is the area where  
17 you build more wind in Tehachapi, and you build more solar  
18 in the Mojave Desert, and you develop those kinds of  
19 renewables.

20          We found significant congestion south to north on path  
21 15. It shouldn't surprise you because we have all these  
22 renewables in Southern California.

23          We found that we needed nine new transmission lines,  
24 that's total of nine. Some of those have already been  
25 started. The Sunrise Project's already been approved, but

1 it's not built yet.

2 So it includes Sunrise, they include Devers/Palo Verde  
3 Number 2, they include Greenpath North, they include the  
4 existing, new Tehachapi line, but they add some other lines  
5 that need to be developed.

6 Now, we're saying nine. It isn't an exhaustive  
7 analysis, it could be eight, it could be 12, it's in that  
8 range.

9 E-3 has suggested 11, in the PUC study that they just  
10 did.

11 So we're looking at new transmission lines.

12 We found that we needed intra-hour flexibility  
13 throughout the WECC. We built out the WECC, also.

14 This wasn't simply build out California and use no  
15 build out in the Western United States, we built out the  
16 Plexos model in our database throughout the WECC.

17 We had about 14 percent renewables throughout the WECC,  
18 not counting California, we were at 33 percent. And found  
19 that when we got, started to get around 32 percent or  
20 slightly above, we were running into significant problems  
21 WECC-wide on trying to find homes for energy. We called it  
22 dump energy.

23 So we had hours when we had dump energy. Dump energy  
24 being defined as we could not find a home at any price for  
25 energy, meaning there is no place to put it. That's why

1 we've got to look at storage options so we can shift this  
2 energy usage.

3 We found that we need resources that respond quicker to  
4 some of our old resources. We need to have quick start,  
5 quick response resources in the future because of some of  
6 these changes in intermittent output.

7 And another big finding was, and you've probably heard  
8 a lot of it, but I'll say it again, this is not the way to  
9 reduce GHG. The cost per ton of GHG reduction was \$180 a  
10 ton for this incremental amount of renewables.

11 We know that isn't the only reason for building  
12 renewables, but it isn't the most cost-effective way to  
13 reduce GHG.

14 What were the uncertainties? The big uncertainties  
15 coming out of the study were quite simple, we thought, and  
16 Nexant did most of this analysis, that the infrastructure  
17 for building windmills in the United States and worldwide  
18 was there. There was probably enough infrastructure to add  
19 the wind at a rate rapid enough to meet our goals by 2020.

20 We weren't so sure about solar. Solar is a wonderful  
21 technology, but the infrastructure's not there yet. There's  
22 a huge demand in the world. We weren't sure we could  
23 develop and build enough solar, and/or site enough solar to  
24 meet the targets in this particular study.

25 We did not think we could build all the transmission

1 necessary to put all this together by 2020. And E-3 is  
2 coming to a similar study for the PUC, saying maybe 2024.  
3 I've only briefly read their study, I've been on vacation  
4 for a couple of weeks.

5 But it appears they're thinking 2024 or 25 might be a  
6 reasonable time to get this transmission built but,  
7 certainly 2020 is pushing the envelope.

8 The other big issue was is we assumed, and I talked  
9 about it, but I didn't give you the number, we assumed that  
10 about 10,000 megawatts of existing plant, that you might  
11 consider once-through cooled, was shut down or unavailable.  
12 So we did take those plants out when we did our studies.

13 Arbitrarily picked some units and took them out. We  
14 have no idea which ones might retire. We know that many of  
15 these might be in Southern California.

16 PG&E and San Diego made some recommendations, also, so  
17 we artificially took some out.

18 It will be much, much worse if more of these plants get  
19 shut down.

20 Again, our grid was built around the load being in  
21 Southern California, and I'll speak about Southern  
22 California, and generation being close to load.

23 As you start putting generation further and further  
24 from load, you run into some interesting operating and  
25 transmission issues that are going to have to be solved.

1       So the bottom line was, is the study we looked at,  
2   locking in the resources by 2020, if it was feasible, and we  
3   didn't think it was totally feasible, we ran into some --  
4   starting to kick of some dump energy problems, surplus  
5   energy problems in April, needing some quick start resources  
6   and some fast start resources, and needing WECC-wide  
7   operational coordination to make the whole thing work.

8       So I'm not saying we can't get there, I'm saying  
9   there's some really interesting things we're going to have  
10   to solve as a WECC entity, as well as a California entity,  
11   to effectively utilize all this renewable energy. Because  
12   right now our system sort of isn't designed for it and it  
13   has to be redesigned.

14       The studies that we thought needed to be done in the  
15   long term were interoperability needs, spending, load  
16   following, and regulation. PG&E's started some of that,  
17   both in-state and around the WECC.

18       Improved forecasting was one of our conclusions, that  
19   we have to be able to forecast better.

20       Again, solar's a wonderful technology, but I'm just now  
21   getting into some more detailed, internal analysis. And if  
22   you've seen a PV cell when a cloud comes over, you lose 40  
23   to 60 percent of your output in four seconds.

24       Too many of those is going to cause some interesting  
25   portavations (phonetic) on my system if I haven't got it

1 back up with some battery storage or something else that can  
2 cover for it.

3 And I'm not talking about a megawatt or two, you guys  
4 are talking about 10,000 megawatts of these kinds of  
5 resources, which are very clean, but we have to solve some  
6 of those intermittency issues.

7 We need to do a much more detailed transmission  
8 analysis in the WECC, in the integration of all these  
9 resources.

10 Again, we found significant congestion south and north.  
11 That's not going to be allowed in the current MRTU. They  
12 actually will try to mitigate that somehow, with congestion  
13 mitigation.

14 We're going to have to solve that issue if this much  
15 renewables gets developed in Southern California.

16 We're not saying you can't do it, we're saying there  
17 are going to be some transmission issues.

18 We didn't do a detailed transmission planning analysis,  
19 which means we looked at load flows for a couple of hours.  
20 That isn't the way our transmission people do transmission  
21 analysis, nor the way the ISO does transmission analysis.

22 They look at multiple contingencies under different  
23 hours/conditions. We didn't look at multiple contingencies.

24 Therefore, we have to go back and take a look at that,  
25 because when everybody wants to be connected to the grid, we

1 don't want a single or multiple contingency to bring the  
2 whole grid down. We did not analyze that.

3 The other thing the model did, and PG&E rightly pointed  
4 out, was we tried to model the hydro systems with the best  
5 data that we had at the time, but we didn't take a look at  
6 how many starts and stops this modeling caused of our hydro  
7 resources.

8 I'll use an example, and PG&E can chime in. We allowed  
9 the pumped hydro facilities at Helms to be started and  
10 stopped whenever they wanted to. And they started and  
11 stopped it repeatedly, one hour on, one hour off, one hour  
12 on, one hour off.

13 It might be doable. Antonia probably says, not really,  
14 Mark.

15 But it's going to cause some havoc with their unit, as  
16 well as some operation and maintenance problems in the long  
17 term.

18 So we've got to take a look at can we really flex our  
19 hydro resources as fast as the model is flexing them.

20 Lastly, I'll couch it in models have perfect foresight.  
21 They know in advance what the load looks like, they know  
22 what their resources look like and they try to match the  
23 two.

24 In real life it isn't that simple. We don't have a  
25 production simulation model. And we looked at ten-minute



1 simulations, in some instances, that can predict perfectly  
2 kind of how the model works.

3 And it's where the model thinks you can maybe integrate  
4 all these things, and in the real world we think you're  
5 going to run into a lot more problems.

6 And so we're dealing with the ISO now, and we're  
7 helping the ISO on their integration study. Dave can talk  
8 about it. Edison has committed to a lot of people and a lot  
9 of time to help try to model these E3 cases to see what the  
10 integration needs might be in the long term.

11 We did find, for the Nexant analysis, that the amount  
12 of spin and ramp we needed was doubled, at a minimum, of  
13 what we now need right now. It may be tripled. So we have  
14 to take a look at those kinds of requirements in the future.

15 MS. GRIFFIN: Thanks, Mark. I'm getting whispers from  
16 my leader to move along.

17 Other questions from the dais?

18 COMMISSIONER BYRON: Ms. Griffin, why don't you go  
19 ahead and ask him questions. I have a couple, but I think  
20 it would be better for you to --

21 MS. GRIFFIN: Since I didn't have an opportunity to  
22 review what he was going to say, I didn't prepare any.

23 COMMISSIONER BYRON: Well, is the study going to be  
24 made available, publicly?

25 MR. MINICK: We've made all the input assumptions

1 available a while ago. We will make the conclusions  
2 available.

3 And the questions, when you hear, you have most of the  
4 conclusions, we'll make some other information available. I  
5 think we're still trying to finalize some of the -- the  
6 report has 12 or 15 chapters. We've had a little difficulty  
7 cleaning up all those chapters, but we'll make them all  
8 available.

9 COMMISSIONER BYRON: It sounds very interesting, it  
10 looks like quite an undertaking. Does it include any cost  
11 of financial information?

12 MR. MINICK: It does. Again, the study will come up  
13 with a number that says it's about a six and a half or seven  
14 percent increase in costs. I think we're uncomfortable with  
15 that number, we think it should be closer to 10 to 12  
16 percent. Again, it's not a huge number, but it's in the  
17 range of what E3 is now saying with the PUC analysis.

18 And it depends, again, on operating characteristics,  
19 how much more operating resources we need, as well as  
20 transmission lines, they all determine total cost.

21 MS. GRIFFIN: And would the cost be -- well, this is  
22 almost a tautology. If the load is significantly lower than  
23 what was forecast in 2007, that would make all of this more  
24 feasible?

25 MR. MINICK: Well, yeah, you'd probably need less

1 transmission lines, you'd probably -- see, we'd have to go  
2 back and take a look at it.

3 As Antonio said, you're energy efficiency programs  
4 we've been doing in the State for the 25, or 30, or 40 years  
5 that I've been here, working at Edison, are lowering load  
6 overall and are not controllable, they're energy efficiency.

7 MS. GRIFFIN: Uh-hum.

8 MR. MINICK: As you raise our load factor, you make our  
9 shape spikier and peakier, which means we need more ramping  
10 resources.

11 MS. GRIFFIN: Uh-hum.

12 MR. MINICK: So I can't say that if we're doing more  
13 energy efficiency and lowering our minimum loads, it's  
14 helping our operations a whole lot.

15 MS. GRIFFIN: I was just thinking of the difference  
16 between the 2007 and the 2009 forecast as it's emerging.  
17 The preliminary one which, of course, will change, is  
18 significantly lower, I think it's over nine percent lower in  
19 2020.

20 MR. MINICK: Yes, we will have less need for renewable  
21 resources. They are more costly than conventional  
22 resources, so there will be some decrease in cost and  
23 transmission needs.

24 MS. GRIFFIN: But it also makes it a lot more feasible  
25 to get there, yeah.

1 MR. MINICK: Well, again --

2 MS. GRIFFIN: Fewer lines to build.

3 MR. MINICK: I think nine lines are impossible. Are  
4 seven possible? You tell me. It's going to be quite  
5 difficult to build seven new lines.

6 MS. GRIFFIN: Okay, questions from the audience?

7 COMMISSIONER BYRON: Mr. Brown, come forward.  
8 And Mr. Kinosian has a question, as well.

9 MR. KINOSIAN: Yeah, it sounds like you looked largely  
10 at solar development in the Mojave Desert. The PUC just  
11 approved a 500-megawatt distributed rooftop PV program for  
12 Edison and we're looking at one for PG&E.

13 Did you run any scenarios that looked at large amounts  
14 of development of rooftop distributed solar, instead of  
15 large projects out in the desert?

16 MR. MINICK: We had 2,700 megawatts of distributed  
17 solar in the base case, so it was there in all our cases.

18 And so until they exceed that, it's built into the  
19 thing.

20 We did look at a lot of solar in the desert. There are  
21 slight differences in what our assumptions were and what I'd  
22 use now. PG&E announced a solar project in San Luis Obispo,  
23 and we had a couple hundred megawatts, they may have 800  
24 megawatts there now.

25 So there are slight differences. I can't say that this

1 is an end-all, it's just sort of a kickoff for more studies.

2 MR. KINOSIAN: Okay.

3 COMMISSIONER BYRON: Dr. Brown?

4 MR. BROWN: Yeah, Merwin Brown, with California

5 Institute for Energy and the Environment.

6 A number of times you made the statement that there are

7 a lot of problems with meeting the 33 percent or higher,

8 with the grid operational problems, economic problems, and

9 things like that, and you said but we can do it.

10 And so what I'm interpreting it is you are probably

11 saying that we can keep the lights on, but there must be

12 some kind of cost to that, or a penalty, or extraordinary

13 actions taken. I was wondering if you could elaborate by

14 what you meant by that?

15 MR. MINICK: The study's way of doing it was

16 simplistic. It assumes that you'd store a lot of this

17 energy when it was generated in surplus and use it for times

18 when you needed it for various purposes, and you'd build

19 very quick responding peakers, maybe more than you totally

20 need. But again, this was our way of kind of solving it in

21 the short term.

22 When I say problems, they're not -- it's all these

23 things are issues, let's just say, that need to be resolved

24 by consensus building throughout the State and how do we get

25 there?

1       The part that we can't model very well is how the  
2 market's going to respond to these things. What's going to  
3 be built through the market? We want the markets to exist,  
4 we want renewable markets to exist. So we don't know how  
5 all this is going to develop.

6       MR. BROWN: So uncertainty might be the biggest issue  
7 here?

8       MR. MINICK: Yes.

9       MS. BROWN: I have one quick question. Mr. Minick, are  
10 you planning to release the cost assumptions that were used  
11 in the scenarios for the study?

12       MR. MINICK: Oh, you mean the cost of the renewable  
13 portfolio that we used, as well as the transmission lines?

14       MS. BROWN: Yes, all those costs.

15       MR. MINICK: Yes, we'll make all that available.

16       COMMISSIONER BYRON: Mr. Zichella, good to see you.

17       MR. ZICHELLA: Good morning, Carl Zichella with the  
18 Sierra Club.

19       This conversation this morning points out, I think, a  
20 real weakness in trying to sort out how difficult this  
21 challenge is going to be, because it really is only looking  
22 at the investor-owned utilities.

23       And one of the key recommendations of the Renewable  
24 Energy Transmission Initiative is that we stop doing  
25 duplicative systems, transmission systems for both IOUs and

1   POUs, and we try to figure out a more efficient way, both  
2   for ratepayers and energy development, how we wield these  
3   renewable resources.

4           That being said, LADWP is the largest consumer of coal-  
5   fired electricity in the State. It's not actually looked at  
6   here. However, if we are able to have greater efficiencies  
7   in how we're operating our transmission system, that the  
8   decrease in coal-fired electricity that they buy, which is a  
9   key goal of that utility, could actually increase capacity  
10  on the lines.

11           So it actually may have quite a bit of a factor on how  
12  much energy we can wield from the Mojave, for example, if  
13  we're not wielding out-of-state coal. Or how much  
14  renewables we may be able to bring in from Baja California,  
15  for example.

16           So I'm not saying that it invalidates what we're  
17  hearing about the reliability and the intermittency  
18  problems, but it is a big gap. And we'll bring it up in the  
19  panel this afternoon, too, it is something I wanted to talk  
20  about is the overall system, not just the IOUs in isolation.

21           MR. MINICK: May I respond to that? Our study did  
22  include coal and water resources, and did for all the units  
23  in the State.

24           We did take a look at meeting -- them meeting their  
25  goals, like everybody else in the State.

1           We did use the existing transmission lines to import  
2 power from other states, just for clarification.

3           MR. ZICHELLA: Okay, great. I'm sorry, I  
4 misunderstood.

5           So did you actually look at what would happen if LADWP  
6 were to decrease the amount of coal-fired electricity they  
7 imported and the capacity that would result on the lines as  
8 a result of that?

9           MR. MINICK: We didn't want to make the assumption of  
10 if and when they would reduce their coal imports, knowing  
11 that they do have coal imports, so I'll have to speculate  
12 what it would mean.

13          If they decreased their coal imports, there would be  
14 more import capability from out of state. You could use  
15 that import capability to bring in renewables from out of  
16 state, if it was allowed.

17          But again, we're under the -- the assumptions we used  
18 is that the State would generate most of its resources  
19 internally. Our knowledge of the 33-percent rule seems to  
20 be heading towards that disposition overall, as building  
21 more renewables in the State.

22          Not allowing imports in the State would also change the  
23 skip flows and some of the transmission utilization in the  
24 State, and we could analyze that. I don't think it will  
25 make a huge impact on the overall results.



1 MR. ZICHELLA: Still, it would be nice to know. Thank  
2 you.

3 MS. GRIFFIN: Anybody on the web?

4 MR. MAGALETTI: One more question, please?

5 MS. GRIFFIN: Okay.

6 MR. MAGALETTI: My name is Mike Magaletti, I'm an  
7 Energy Commission employee.

8 Mark, I have a question about one other constraint that  
9 you didn't seem to mention, did you take into account the  
10 availability of offsets for fossil fuel generation that you  
11 might have to add?

12 MR. MINICK: Yes, we did put a carbon tax or an offset  
13 tax, as well as we took a look at RECS in other states in  
14 the setting.

15 MR. MAGALETTI: Offsets as in PM-10, PM?

16 MR. MINICK: We didn't look in detail regarding the PM-  
17 10. Our assumptions were that we would build out the  
18 existing plants that we have contracts, that are currently  
19 in litigation for the offsets, by 1,800 megawatts of new  
20 peaking facilities in one combined cycle in Southern  
21 California. The rest of the peakers were located throughout  
22 the State.

23 In this particular case we added around 23 to 25  
24 hundred megawatts of LNS 100s to make the grid work.

25 MR. MAGALETTI: Thank you.

1           COMMISSIONER BYRON: Mr. Minick, I think while they're  
2 deciding if we're done with the panel, I'd like to thank you  
3 very much for this. The results, the preliminary results  
4 look very interesting. I'm glad this report will be made  
5 available, it sounds like it will be very informative.

6           MR. MINICK: Thank you.

7           MS. GRIFFIN: Okay, thank you.

8           COMMISSIONER BYRON: Do we have any other members of  
9 your panel present, Ms. Griffin, is Mr. Pletka, from Black  
10 and Veatch on the phone?

11          MS. GRIFFIN: Yes.

12          COMMISSIONER BYRON: Do we have time to hear from him?

13          MS. GRIFFIN: I think this would be a good time to hear  
14 from him.

15          COMMISSIONER BYRON: Are you sure?

16          Mr. Pletka, if you're there, we'd appreciate hearing  
17 from you on the study that you did for Redding.

18          MR. PLETKA: Okay. Can you hear me?

19          COMMISSIONER BYRON: Yes.

20          MR. PLETKA: All right, I'm not sure if you're able to  
21 grant me control so I can share my slides or not?

22          UNIDENTIFIED SPEAKER: Yes, you have control now.

23          MR. PLETKA: Okay. Can you give me an idea of how long  
24 you'd like me to talk?

25          MS. GRIFFIN: Ten minutes.

1 MR. PLETKA: Okay.

2 COMMISSIONER BYRON: And while you're looking, let me  
3 ask if by chance Commissioner Levin has joined us by phone?

4 MS. KOROSEC: Not that we're aware of.

5 COMMISSIONER BYRON: All right, thank you.

6 MR. PLETKA: Can you see the Power Point slide I put  
7 up?

8 MS. GRIFFIN: Yes.

9 MR. PLETKA: Okay, great. Thank you very much for  
10 allowing me to speak this morning. Again, my name is Ryan  
11 Pletka, I'm with Black and Veatch.

12 We were the principal technical and economic consultant  
13 to phase one of RETI, and so let me just get into it.

14 So, yeah, RETI stands for Renewable Energy Transmission  
15 Initiative. It's also important to understand an other  
16 acronym, CREZ, which stands for Competitive Renewable Energy  
17 Zone.

18 The CUC maintains a very active website, a lot of  
19 documentation, so I encourage people to go there. There are  
20 really thousands of pages of reports.

21 It's important to note that really RETI's a  
22 stakeholder's process, and so what I'm talking about today  
23 really only represents my opinion.

24 I was the project manager for Black and Veatch and did  
25 play a key role in the assessment.

1       And our role was largely involved in phase one of the  
2 project, and the project is currently in phase 2a, and I'll  
3 describe that here in just a minute.

4       For those of you not familiar with RETI, it's a  
5 statewide planning process really intended to identify the  
6 next ten large-scale transmission projects needed to  
7 accommodate California's goals for renewables, including the  
8 20 percent by 2010 goal and, more importantly I think, for  
9 transmission planning purposes, 33 percent by 2020.

10       It has of course been recognized in California that  
11 transmission really is a limiting factor in order for the  
12 State to meet these goals, because you're going to deal with  
13 very large-scale renewables.

14       And so the purpose of RETI then was to identify those  
15 kinds of the best economic options, and also those that had  
16 the least environmental negative impact.

17       We defined early on some common terminology in the  
18 process, and renewable energy zone really is a collection of  
19 pretty dense, relatively dense renewable resources that when  
20 you group them together, they have a combined economies of  
21 scale. Also, they share some transmission constraints and  
22 could be developed around the same time frame.

23       So a big part of the RETI process was to identify these  
24 cultures of renewables around the State and map them.

25       There are a lot of stakeholders in the RETI process, so

1 certainly it's been very helpful to have the input of all  
2 these different groups, all the transmission providers, or  
3 the major transmission providers and load-serving entities  
4 in the State, as well as representatives from the  
5 generators, public interest groups, like the Sierra Club,  
6 and the various permitting agencies.

7 I think a unique aspect of RETI, really compared to a  
8 lot of other studies that have been done out there in the,  
9 you know, the history of California renewables planning is  
10 that there's been really very engaged stakeholder dialogue  
11 throughout this, and every decision is carefully considered  
12 by the stakeholder steering committee and the other working  
13 groups that are part of the RETI process.

14 Okay, so an overview of the RETI phase is the first  
15 phase which is identifying and ranked these competitive  
16 renewable energy zones. That phase was really completed at  
17 the end of last year.

18 The second phase is now to develop a statewide  
19 conceptual transmission plan to access those zones. And  
20 draft A, 2a report is out for comment on the RETI website.

21 The intent is that after there's some consensus  
22 agreement on what the conceptual transmission network will  
23 look like, then the utilities or other project proponents  
24 will then develop detailed plans of service for specific  
25 lines that are part of the conceptual transmission plan and

1 that will then go into the permitting process.

2 The overall hope and objective is that if we all get  
3 together and plan this system from the outset that there  
4 will be a more smooth and streamlined process getting to  
5 actual implementation of these projects.

6 So I just want to provide some highlights of the phase  
7 one process. This represents the states that we looked at.  
8 Primarily, the process focused on in-state resources, and we  
9 did look at renewables in adjoining states, although at a  
10 less -- in less in-depth in phase one of these.

11 People should know that there's another process that's  
12 analogous to RETI for the rest of the western  
13 interconnection, and that's the Western Renewable Energy  
14 Zone project, and that's sponsored by the Western Governor's  
15 Association, in cooperation with the DOE.

16 And there's a website for that process and a lot of  
17 great data, with all the developed sites for that process.

18 There's a key map, for example, that shows the  
19 distribution of renewables throughout the west, and this is  
20 a representation of where those renewables are. The bluish  
21 areas are wind, the yellowish areas are high installation  
22 solar, the red triangles represent geothermal, and the green  
23 circles represent hydro.

24 So as part of the Western REZ process we now have kind  
25 of a consolidated dataset that puts renewables on kind of a

1 comparable basis state by state by state.

2 The circles on these -- on this map represent what REZ  
3 calls hubs, which are kind of super regional concentrations  
4 of renewables.

5 And I'd say that the Western Governor's Association  
6 process is a much higher level study than the California  
7 RETI process. In California we got much more detailed on  
8 the location of specific promising project opportunities,  
9 rather than very large-scale concentration of renewables.

10 I'll skip through this line in the interest of time.  
11 One of the specific questions was how did RETI access the  
12 amount of renewables to meet the 33 percent target?

13 And from the point of consideration that, really, the  
14 overall objective, I mean from the outset of RETI, is to  
15 identify large-deal transmission solutions to meeting  
16 renewables.

17 So that having been said, really, the key thing is not  
18 to really go out and identify all the rooftops that might  
19 support solar photovoltaic resources, but we did take those  
20 into account in calculating what's called the RETI net  
21 short.

22 So that RETI net short, there's a formula there that  
23 really does, you know, here's the sales in California 2020,  
24 here's the RPS requirement. And then we take out operating  
25 resources, the Go Solar Initiative, various other things to

1 arrive at an all-in number of about 60,000 gigawatt hours  
2 per year needed by 2020.

3 And then the thing, too, it's important that you know  
4 that RETI is actually planning to exceed that net short  
5 because there's a lot of concern that it's not all ten, or  
6 how many of these lines will actually make it, and also we  
7 want to encourage competition around the State and not just  
8 plan to meet all of our renewables from one profit base.

9 Let me go ahead and skip this. But just to give you a  
10 highlight of these, you know, there's a lot of environmental  
11 considerations that went into it. We have a series of maps  
12 that show all the different restrictions on development in  
13 California.

14 You should know that this slide right here, this is for  
15 wind -- wind resources. And the key take-away is the white  
16 area represents the land that's available and suitable for  
17 wind development, and this is around the Tehachapi area  
18 between Bakersfield and Edwards Air Force Base.

19 We did do this pretty extensive environmental screening  
20 process, with the input of the environmental working group,  
21 and the end with all of that was the identification of these  
22 clusters of renewable areas.

23 This shows Southern California. And you can see the  
24 gray represents kind of a conceptual boundary for these  
25 competitive renewable area zones.



1       Here is like Tehachapi, Fairmont, Kramer. The orange  
2 circles are solar projects. The purplish areas are wind  
3 project. And then we have, there's some green and it  
4 represents biomass and geothermal.

5       But largely in Southern California there's a lot of  
6 solar and a lot of wind.

7       And then sort of the final output, I'll jump ahead a  
8 couple of slides, there is an economic assessment which  
9 produced a relative rank cost, in dollars for megawatt hours  
10 for all these different areas, and so each of the zones were  
11 stacked in this.

12       And remember, on the bottom axis that we need about  
13 60,00 gigawatt hours per year, so there's plenty of  
14 resources out there and available, and there are certainly  
15 areas that are more cost-effective to develop than other  
16 areas.

17       This is the phase one assessment. Phase two intends to  
18 revise some of these numbers, so please keep that in mind.

19       And then one final slide I'll end with, and then we can  
20 turn it back to the panel.

21       Economics was really the focus of Black and Veatch, but  
22 they did a great amount of work to identify environmental  
23 constraints and concerns associated with these different  
24 zones.

25       And phase one was known to range from zero to 12 in

1 terms of the relative environmental concerns.

2 Zero and lower scores would represent areas with  
3 potentially fewer environmental concerns, rather than the  
4 higher scores represent more environmental concerns.

5 Certainly, on economics, negative numbers represent a  
6 better scoring area in terms of economics, than the higher  
7 cost areas that are on the top of the chart.

8 So you can see Imperial North A, that's what that  
9 designation is, that circle in the lower left-hand corner  
10 is, in phase one came out being one of the lowest cost  
11 resource areas, but also the least environmental concerns.

12 This is a geothermal area in Southern California,  
13 Imperial Valley.

14 The Salton Sea area, known for some time to be a  
15 promising area for geothermal development, relatively high  
16 density development from the land areas, so that's why it  
17 got relatively good scores in both of those categories.

18 So bear in mind that these are phase one results.  
19 There are phase two results that are now in draft and I  
20 encourage people to review the phase two process because it  
21 has a different take on the assessment, and kind of  
22 transitioning from looking at resources to now the  
23 transmission resources that we need to access these  
24 different areas around the State, and a ranking of those  
25 from a similar type perspective.

1 Thank you very much.

2 MS. GRIFFIN: Do you have any questions from the dais?

3 COMMISSIONER BYRON: No. Very good, Mr. Pletka, a  
4 good, quick summary, and I think we've certainly learned a  
5 lot from the RETI work. And because it represents  
6 stakeholder involvement, and early involvement of the  
7 environmental community, and I think there's 29  
8 stakeholders, we've certainly benefited by all their input.

9 I would turn to a gentleman that's in the audience, who  
10 pointed out earlier, Mr. Kelly, that it may have also  
11 clearly indicated that we need to consider joint projects.  
12 And I don't think RETI's responsible for it, but it's had a  
13 great deal of influence and perhaps the creation of a new  
14 joint planning group with regard to transmission planning in  
15 the State, with publicly-owned utilities, investors, and the  
16 ISO.

17 Mr. Kelly, is there anything you wanted to add with  
18 regard to the presentation that Mr. Pletka just gave, seeing  
19 as you've been very much involved with this, Chairing -- I  
20 should say co-Chairing the environmental working group?

21 MR. KELLY: Thanks, Commissioner Byron. The only thing  
22 I would say is that one of the things that we did learn  
23 throughout this process is that many of the transmission  
24 improvements that we need to make are really based around  
25 upgrading our existing system.

1           We talk about needing a dozen new lines. I think a lot  
2 of that is not actually new corridors and new lines, its  
3 existing lines that are being upgraded, their capacity  
4 increased.

5           There will be some collector lines that are going to  
6 need to be built, that's for sure, but I think a couple of  
7 trunk lines. But by and large about 80 percent, roughly, of  
8 what we need to do, maybe more, will be done by upgrading  
9 our existing transmission infrastructure in accordance with  
10 the Garamendi Principles.

11           COMMISSIONER BYRON: Excellent, thank you.

12           So I don't have any questions for Mr. Pletka. That was  
13 very good, a very concise presentation.

14           Do we have any questions from Karen, do you have any  
15 questions?

16           MS. GRIFFIN: No.

17           COMMISSIONER BYRON: How about from the audience?

18           MS. GRIFFIN: Okay, I think we're ready to go to the  
19 second panel then.

20           COMMISSIONER BYRON: Gentlemen, thank you very much.  
21 Ms. Griffin, thank you.

22           We may have gone a little bit long, but I think very  
23 worthwhile information. Appreciate your being here very  
24 much.

25           (Off the record.)

1           MR. ALVARADO: Good morning, my name is Al Alvarado;  
2 I'm with the Electricity Analysis Office, here at the Energy  
3 Commission.

4           For this second panel we have another set of studies  
5 that I think do compliment the studies that were presented  
6 today by PG&E, Edison, and Black and Veatch.

7           I do note that each study does take a somewhat  
8 different perspective and also use a different set of  
9 assumptions. But each do provide a unique perspective on  
10 how to address the impacts and concerns associated with  
11 meeting the 33 percent renewable targets.

12          For this second panel we have Nancy Ryan, with the PUC,  
13 that will be able to provide an overview of the study  
14 that -- the preliminary study and findings that they've  
15 recently -- the study that they just recently released.

16          We do have Dave Hawkins, with the Independent System  
17 Operator that is -- has and is conducting an operational-  
18 related type study.

19          From our staff, Angela Tanghetti will provide an  
20 overview of the system studies that we have done, that I  
21 think also provides a somewhat different perspective and use  
22 of assumptions that the other studies have included.

23          And we also have Geoffrey Brand, from ICF, that has  
24 been under contract with the Energy Commission to evaluate  
25 the implications of the natural gas system.

1 I know that some of you do have some presentations. I  
2 mean, you're welcome to come to the dais if you want to use  
3 any of the slides, and we can run through the list of  
4 questions.

5 MS. KOROSK: I can actually run your slides for you,  
6 if you'd rather stay at the table.

7 COMMISSIONER BYRON: Dr. Ryan, welcome back.

8 MS. RYAN: It's a pleasure to be here again,  
9 Commissioner Byron, and advisors.

10 COMMISSIONER BYRON: I have a new acronym as a result  
11 of your last visit.

12 MS. RYAN: Which one is that?

13 COMMISSIONER BYRON: It's an AFZ, acronym free zone.

14 MS. RYAN: Acronym free zone. All right, well, I'll do  
15 my best today to recreate the acronym free zone.

16 And I need to apologize in advance that I am going to  
17 need to speak and run today, so I will certainly stay around  
18 after I give my presentation to answer any questions from  
19 you all, the panel, or the audience. But then our staff  
20 will provide responses to any additional questions in  
21 writing, as we have already done so far.

22 And speaking of our staff, let me take a moment to  
23 recognize Angelette (phonetic), and Jaclyn Marks, who are  
24 sitting in the audience today. Not to put them on the spot  
25 after I leave, but just to acknowledge the very hard work

1 that they and others put into this study, which I have the  
2 privilege to present to you.

3 So, let's see, you would think I would have the hang of  
4 this by now.

5 I will be offering a fairly high level analysis of this  
6 very detailed study to give you a flavor of the types of  
7 things that we looked at, and the principal conclusions that  
8 we reached and their implications for policy decisions.

9 And then as I said, we can follow up with more detailed  
10 responses later.

11 So as I was thinking about my remarks today and how to  
12 characterize this work, I was thinking really in a sense  
13 this is fundamentally a study about logistics, the logistics  
14 of reaching our 33 percent RPS target.

15 And of course, those of -- anybody here who's a study  
16 of history, and particularly military history, as I am, is  
17 aware that there are sort of many famous quotations from  
18 military leaders and historians about the importance of  
19 logistics.

20 Such as "forget logistics you lose," from one of  
21 General Schwarzkopff's Desert Storm corp commanders.

22 All the way to Alexander the Great who said, "my  
23 logisticians are a humorless lot, they know if my campaign  
24 fails they are the first ones that I will slay."

25 (Laughter.)

1 MS. RYAN: So in that spirit I will offer you our  
2 analysis, first really what I consider to be our logistical  
3 analysis of timelines, and risks associated with getting to  
4 33 percent, and then the cost analysis which is really,  
5 again, about what are the resources that we need to deploy  
6 to get to 33 percent by various paths, and what kind of a  
7 price tag can we put on them today.

8 So listed on this slide are just various types of  
9 questions that we answered and I've kind of danced around  
10 them in my introduction to the study.

11 But essentially we're looking at what do we need to do  
12 to get to 33 percent and how much will it cost?

13 How do various contingencies, sort of different future  
14 states of the world change those estimates and what are the  
15 implications for fundamentally how much flexibility should  
16 we build into our strategy.

17 So the first question that we answered and I know this  
18 is the subject of, perhaps controversy is too strong a word,  
19 but anyway an effort to reconcile the fundamental  
20 assumptions in different studies is we began by asking,  
21 well, to get to 33 percent RPS what -- by 2020, what  
22 additional resources will be needed?

23 And so our point of departure was that to get to 20  
24 percent in 2020 we would need to slightly more than double  
25 existing renewable generation from 27 terawatt hours per



1 year in 2007, to 35 terawatt hours per year in 2020.

2 Upping the goal to 33 percent RPS means that we need a  
3 total of 75 terawatt hours per year in 2020, in excess of  
4 the present 27 terawatt hours per year.

5 And each of those scenarios or targets has different  
6 levels of transmission investment associated with them for  
7 new transmission lines, some of which are -- I think most of  
8 which are already in the works for the 20 percent case.  
9 Seven new transmission lines for the 33 percent RPS case.

10 And these are what we call our reference cases. And  
11 you will see that other cases that we examined deviate from  
12 the reference case with more or less predictable  
13 consequences.

14 Okay, I mentioned that there are -- so the sort of  
15 basic premise of this study is that there are numerous paths  
16 to attain a 33 percent RPS. And what we tried to do in this  
17 piece of work is to put some structure on that question of  
18 what are the different paths?

19 So we began with two reference cases, the top two lines  
20 in this table, the 20 percent RPS in 2020, and the 33  
21 percent reference case in 2020. Those cases are based on  
22 what's already contracted, what's already in the pipeline,  
23 so essentially a project of the current approach.

24 Then we looked at some alternatives that would  
25 essentially involve shearing off in different directions.

1 So a high wind case in which we -- that's self-evident.

2 A high out-of-state delivered case, so relax  
3 restrictions on importing electricity, but maintain a  
4 deliverability requirement, so this is not a tradable RECS  
5 case, and a high DGS case.

6 So those are kind of the range of futures that we  
7 looked at.

8 Actually, before I go into that maybe I should say a  
9 little bit more.

10 Okay, but anyway, I'll come back to these cases when I  
11 get to the cost analysis, that's primarily where they figure  
12 in.

13 I want to take a few minutes first, however, to talk  
14 about the timeline analysis, which is based entirely on the  
15 33 percent RPS reference case.

16 I think in the second stage of this report we may look  
17 at doing this kind of timeline analysis for some of the  
18 other cases, but the 33 percent reference case is the point  
19 of departure.

20 So the essence of this exercise, this timeline  
21 analysis, was really to pull together everything that we  
22 know about what new resources, realistically might be  
23 developed in a given -- in this 33 percent reference case,  
24 so again, ones that are in the pipeline.

25 The transmission needs that they have, the implications

1 for who will be doing the siting, whether it's local  
2 authorities, this body, the PUC for transmission, the extent  
3 to which Federal agencies would have to be involved, and to  
4 try to pull all of that information together and look,  
5 really for the first time, at what is the overall set of  
6 activities that have to be completed looking across projects  
7 and across agencies in order to get to 33 percent. So what  
8 resources, in the broadest possible sense, do we need to  
9 deploy to get to that 33 percent goal?

10 And then how do the reforms that we're working on, in  
11 terms of the siting processes, how do they help?

12 And then what types of risks might we encounter and how  
13 could they throw us off course, what kinds of monkey  
14 wrenches -- you know, if you throw various monkey wrenches  
15 into the timeline, what are the consequences?

16 And so this is a -- I don't think anybody's done  
17 anything like this before in California. And I'm sure that  
18 with more time, and effort, and thought it could be done  
19 better. So this is timeline 1.0.

20 And not to be confused with timeline number 1, which I  
21 will now introduce.

22 So timeline number 1 is, in a sense it's already the  
23 past. This is a timeline which shows each line in here is  
24 essentially a renewable energy -- is a renewable energy  
25 zone. And each sequence of colored bars, end to end,

1 represent all the various steps in bringing the energy in  
2 that zone to market.

3 Beginning on the left and gold, with transmission  
4 planning, going all the way through the various siting  
5 processes, construction and interconnection.

6 And what this shows is that we would have a large  
7 number of projects simultaneously going through different  
8 stages of the permitting processes and being developed more  
9 or less simultaneously with slight -- they're offset  
10 slightly to account for the fact that there's only so much  
11 that any one agency can do at any one time.

12 So this, again, as labeled represents historical  
13 experience without process reform, so it's based on in the  
14 past how long, on average, has it taken different types of  
15 agencies to do different types of activities? How long has  
16 it taken the utilities or the developers to do their part,  
17 and adding it all together and sequencing it in a meaning --  
18 you know, in a reasonably meaningful way.

19 And you'll see that with this approach, when we get to  
20 2020, which is the vertical red line, a number of projects  
21 have not come online yet. And in fact, the last ones do not  
22 come online until 2024.

23 So that says without changes we would never get to --  
24 we could never realistically expect to get to 33 percent by  
25 2020.

1        Now, the good news, as all of you know, is that there  
2   are a lot of changes already in the works at this agency, at  
3   the PUC, at the ISO and I think, most importantly, involving  
4   us collaborating among ourselves, as well as with the  
5   Federal agencies.

6        And but this timeline, what it does is take the same  
7   set of projects and the same activities, but to factor in  
8   the potential savings, time savings resulting from some of  
9   the ongoing reforms.

10       And it is a little difficult to read, it looks like  
11   something maybe out of a scrapbooking catalogue. But the  
12   main innovation here is that you see some of these bars have  
13   been compressed and some of them now are, you know, on top  
14   of each other.

15       And that's where you see these checkered patterns  
16   showing up is where you have essentially parallel processing  
17   going on within the agencies for given projects.

18       And the effect of that is to compress the timelines for  
19   all of these projects, and now you see the last one comes  
20   across the finish line in 2020 and that's a much more  
21   satisfying result.

22       And perhaps we could do even better than that with  
23   further process reforms than the ones that are in the works.

24       Now, returning to military history, not Clausewitz, I  
25   thought it was him, but it was actually the Prussian Chief

1 of Staff, Field Marshall Moltke once said, and people have  
2 often heard this one, "no battle plan survives contact with  
3 the enemy."

4 So there's all kinds of things that will happen once we  
5 go on and try to build all these projects, lots of surprises  
6 will happen. The case that we just looked at is a best  
7 case.

8 And this timeline to be is an attempt to ask the  
9 question, okay, what if some mini of the -- just a few, I  
10 would say, just a few of the, you know, mini-contingencies  
11 that might occur do occur, what are the implications for the  
12 timeline analysis that we just completed.

13 And this -- and again, we've picked on specific  
14 resource zones more or less in a random way, so there's no  
15 prediction here at all on the part of PUC staff that any  
16 given project is prone to fail in any specific way.

17 So the examples in here, you'll see where there's red  
18 text added, and are one in transmission zone two, generation  
19 fails to develop, transmission costs stranded in the near  
20 term.

21 So that would be an instance where a transmission line  
22 is approved, construction starts but, for ever reason, for  
23 technology failure, a barrier to permitting, financing  
24 problems, for whatever reasons the generation simply does  
25 not materialize, so that zone does not pan out.

1           In zone three we have a different adverse outcome  
2 illustrated, transmission permit denied, environmental  
3 impact too hot. So that might be the PUC or the BLM simply  
4 says, no, we cannot find a way to permit transmission into  
5 this zone so it will not be developed.

6           Now, this is kind of a static case in that if these  
7 kinds of things happen, as we saw them coming, of course,  
8 you know, there would be adaptive measures taken. And so  
9 there are ways to still ensure that we would eventually get  
10 to 33 percent.

11          But the main point of this is that if those things  
12 happen far enough along in the process, we're not going to  
13 be able to turn around and do something else, or not  
14 necessarily be able to turn around and do something else in  
15 the time frame to get to 2020, so that's the main message  
16 there.

17          Okay. I would say the other thing that is important  
18 about this analysis, that I think we have not yet really  
19 fully developed, but I think is really worth something that  
20 it should be able to do for us is to really unpack these  
21 various bars here and talk about, you know, what level of  
22 effort is involved in all the agencies, utilities, at the  
23 developers to make all these things happen in this time  
24 frame simultaneously?

25          Not just the parallel processing for individual

1 projects, but moving all these projects through the siting,  
2 permitting, construction interconnection process at the same  
3 time.

4 Any my sense is that it will require a level of effort  
5 much greater than what has been expended so far, and that's  
6 something that needs to be taken into account in planning  
7 and budgeting, both within the public and the private  
8 sector, and that's one of the messages of this report.

9 I'm going to pass over this and it's discussed in the  
10 report.

11 But let me just close with I think the other key  
12 message from this timeline analysis, which is that moving  
13 forward we need to build flexibility into the way that the  
14 RPS program is administered. I think that's one of the key  
15 lessons from this analysis.

16 And that we need to have strategies that enable us to  
17 manage the many risks that we face for getting to 33 percent  
18 RPS.

19 Your staff asked us for examples of those and the last  
20 three bullets in this slide are examples. So we could plan  
21 for more transmission and generation needed to reach 33  
22 percent, anticipating that some projects will fail for  
23 reasons that we, you know, cannot know at this time.

24 We could focus more on distributed solar PV, which does  
25 not require new transmission so it removes one risk but, you



1 know, substitutes others.

2 Could concentrate on pre-permitted land that could be  
3 set aside as renewable energy products.

4 So those are examples of things that we might do.

5 The second phase of this project, that will be  
6 reflected in the final report due later this year, will be a  
7 more thorough discussion of mitigating strategies.

8 Okay, let me turn now to the cost analysis, which again  
9 I think also, in a large sense, is effectively a logistical  
10 analysis, but it also sheds additional light on the  
11 questions of risk and timing.

12 So as I told you when we started, in addition to the  
13 reference cases, the 20 percent RPS and 33 percent RPS  
14 reference case, we developed three other cases which are on  
15 the right-hand set of bars in this diagram.

16 And again, they represent different paths and, as you  
17 can see here, different resource mixes for getting to 33  
18 percent RPS. So not surprisingly, the high wind case has a  
19 lot of land.

20 The high, out-of-state delivery case has a lot more, a  
21 good bit more out-of-state resources. That's the line with  
22 the diamonds, the percent of out-of-state resources for the  
23 total amount of out-of-state resources, and it also has a  
24 lot of wind.

25 The high DG case, a lot more solar PV. And generally,

1 as you go from less to right, there's less solar thermal.

2 Other elements of the resource mix don't change quite  
3 so much.

4 And again, I'm going to remind you there's no tradable  
5 RECS case in here, these are strictly delivered cases.

6 So I'll talk about the substance of this table in a  
7 minute, but I want to stress that in contrast you have the  
8 work that we've done is often presented in the media, the  
9 really important aspect of this work is not the total price  
10 tag of any given pathway, it's really the comparison of a  
11 given pathway to the reference cases, the incremental cost  
12 of going to 33 percent by one means or another relative to  
13 our estimate of the cost of getting to the 20 percent RPS in  
14 2020, which is the current law in the State.

15 And so we broke this down by different pieces, and I'll  
16 leave you at your leisure to study this table. But you can  
17 look at the sort of relative roles of transmission versus  
18 generation investments in these different cases.

19 The other thing I want to point in here, before I get  
20 into the detailed results by case, is that the bottom two  
21 lines in here are the two different metrics that we're using  
22 to talk about cost. It's impossible to break cost down into  
23 any meaningful way that represents what's on customers'  
24 bills because our rate structure is so varied and  
25 complicated in California.

1        So we approached the matter of cost in two different  
2 ways. Total, statewide electricity expenditures, which I  
3 think is really our preferred metric, is essentially the  
4 revenue requirement for all of California, public and  
5 private utilities added together.

6        How much more will we be spending on renewable energy  
7 than we would -- or how much more will we be spending on  
8 delivering energy than we otherwise would, absent this  
9 increase in the RPS.

10       The bottom line, average statewide delivery cost for  
11 kilowatt hour, we just divide it in kilowatt hours  
12 delivered. And that line is somewhat sensitive, of course,  
13 to what we assume about demand response in particular energy  
14 efficiency.

15       Okay, so here, this table is kind of the punchline for  
16 the cost analysis, and it summarizes the two reference, the  
17 findings for the two reference cases and then the three  
18 alternatives in terms of their total statewide electricity  
19 expenditures on the top line, average cost per kilowatt  
20 hours I just discussed.

21       And then I think the third line -- the third line I  
22 think is the most -- the third and fourth lines are the most  
23 important ones.

24       So the absolute difference in dollar terms, in the cost  
25 of that case relative to the 20 percent RPS case, and then

1 it's also expressed in percentage terms.

2 So what you can see is the 33 percent RPS reference  
3 case, so again, essentially a projection of the status quo,  
4 the approach we're pursuing now is approximately seven  
5 percent more expensive in 2020, than if we stuck with the 20  
6 percent RPS, the current policy.

7 Some of the other alternatives are actually less  
8 expensive, somewhat less expensive, I don't find the  
9 variation here to be particularly striking.

10 So the wind cases are a little bit less expensive. The  
11 high DG case is a good bit more expensive. But they're all  
12 in the same order of magnitude.

13 So to me that's the good news from this study is that  
14 we are not talking about a -- I mean, this is not chump  
15 change, we're talking about giving you the absolute dollars.  
16 But in percentage terms these changes are not enormous, as  
17 has sometimes been suggested.

18 And these costs do include things like renewable  
19 integration, these are all in costs. These are more --  
20 these are levelized annual cost, so they're more akin to  
21 what is my mortgage cost than what did I pay for my house.

22 But that's a more meaningful metric, I think, when you  
23 talk about what are the implications for rates.

24 This is just another way of looking at those results  
25 and I won't talk about that.

1           So let me close -- actually, I have two things to close  
2 on. So let me take a few minutes to talk about the  
3 sensitivity analysis that we did and note simply that there  
4 is a great deal of uncertainty about many of the important  
5 variables that have to be considered in an analysis like  
6 this.

7           And I fully expect that people can, will, and should  
8 disagree about the assumptions that we made in our base  
9 cases, or our reference cases.

10          And in order to address some of the concerns that we  
11 anticipated that parties would have and, frankly, also to be  
12 responsible as analysts, we conducted a sensitivity analysis  
13 that varied a number of those particularly important driving  
14 variables.

15          And I should note that these are one way or partial  
16 sensitivity, so we're varying one thing at a time. We  
17 didn't do scenarios where -- best case or worst case  
18 scenarios, for example, where we looked at very multiple  
19 uncertainties at the same time.

20          So obviously one of the areas where people disagree the  
21 most and, again, where there is the most uncertainty is the  
22 future trajectory of natural gas prices.

23          And even more uncertain is the path that greenhouse gas  
24 allowance prices will take if, and when, a market for those  
25 allowances is created.

1           And so we had to make assumptions about both of those  
2 things over this 12-year horizon.

3           And so what we did is examine some bracketing cases  
4 around our base case assumptions and those are illustrated  
5 here. So what you see are the diamonds, and each line  
6 represents one of the cases.

7           The 2020 all gas scenario is a case, I haven't talked  
8 about that very much, but that's a case where we build no  
9 more renewables, we just build gas build-out to 2020. And  
10 that's very akin to the CARB business as usual case in the  
11 scoping plan.

12           And then the other two cases you're familiar with now,  
13 20 percent RPS reference case, 33 percent RPS reference  
14 case.

15           So and then along the bottom, statewide electricity  
16 expenditure.

17           So you see they're somewhat higher on the 20 percent  
18 higher RPS case, a good bit higher in the 33 percent case.  
19 Those are the diamonds in the middle.

20           And then the lines that bracket those diamonds show how  
21 the bottom line varies as we either raise the gas price and  
22 the greenhouse gas allowance price going to the right, or  
23 lowering it within a range that was derived based on input  
24 we got from parties.

25           And I think the one major takeaway here is that even at

1 a very high gas price and allowance price the 33 percent RPS  
2 is still a little bit more expensive than the all-gas  
3 scenario, and a little bit more expensive than the 20  
4 percent RPS reference case.

5 That's not to say that closing that gap is not valuable  
6 to consumers, that's a different -- that's a different  
7 calculation. But you have to really push the gas price up  
8 and the allowance price up extremely high before we would  
9 actually see 33 percent RPS cheaper than an all-gas  
10 alternative.

11 We also looked at a low load sensitivity case, and this  
12 turns out to be a very important case because this analysis  
13 was based on the 2007, the 2007 IEPR, which was published  
14 both before the CARB scoping plan and before the current  
15 economic downturn occurred.

16 So what we see now is load growth, this load has  
17 dropped some and the pace of growth is not as high as it  
18 once was. In addition, the State has made a public  
19 commitment to higher levels of investment in energy  
20 efficiency.

21 And this low load case more closely approximates the  
22 inclusion of those two factors into the model.

23 And what you can see here is, again, the 20 percent RPS  
24 reference case and 33 percent reference case contrasted in  
25 the first two lines, the total of statewide expenditures in

1 those two cases under the base case assumptions, and then  
2 under the low load sensitivity.

3 And so in both instances they're somewhat less  
4 expensive. Costs, overall costs go down on order of about  
5 ten percent.

6 But again, the thing I think is most important to look  
7 at is, well, what's the incremental cost of the 33 percent  
8 RPS relative to the 20 percent, the status quo?

9 And the gap is actually a little bit bigger in the low  
10 load sensitivity than it is in the base case. And you can  
11 see that both in absolute and in percentage terms here. The  
12 difference is not very great.

13 And given the uncertainty of the types of variables  
14 we're dealing with probably within the noise.

15 But it's instructive to understand what it is in the  
16 model that drives that finding. And what happens is when  
17 you have low load growth, either due to poor economic  
18 conditions and/or success of your aggressive energy  
19 efficiency programs, you reach a point where new renewable  
20 energy investments are no longer displacing new investments  
21 in fossil-fired plant, they're simply driving out existing  
22 fossil-fired plant.

23 And from an environmental perspective that's still  
24 desirable, but from an economic perspective it says now  
25 we're not saving money anymore, we're not avoiding the cost



1 of building new plants by building a renewable plant, or  
2 we're not avoiding the cost yet, so we're retiring,  
3 essentially shelving a useful asset. So that makes the 33  
4 percent RPS case more expensive relative to the 20 percent  
5 case, in which it is still the case that all additional  
6 renewables do drive out new investment -- investment in new  
7 fossil-fired plant.

8 And that raises questions that I don't think we've  
9 fully explored yet in this study about the interactions  
10 between the energy efficiency programs and the RPS program,  
11 and I think highlights the need for the kind of integrated  
12 resource planning, and I know many people cringe at the use  
13 of those words, but the type of planning exercise that at  
14 least for the IOUs the Commission is conducting in the long-  
15 term procurement planning process, where there really is an  
16 opportunity to trade off these different types of resources.

17 The last sensitivity case I'll talk about is one that I  
18 know is of great interest to some stakeholders and that is,  
19 well, we have high hopes for solar energy in California, for  
20 the potential of our investments through the CSI and other  
21 programs to bring down the cost of -- the installed cost of  
22 the delivered cost of energy from solar photovoltaic  
23 installations.

24 And what we explore in this case is, well, what if --  
25 what if what the industry is telling us they can do they do,

1 they do do it and it materializes?

2 So contrasted here in this bar chart, each pair of bars  
3 is again for one of the cases, 20 percent RPS reference  
4 case, 33 percent, and the high DG case.

5 And it's, again, the statewide expenditure, it's total  
6 revenue requirement.

7 On the left on the base case, the dark blue and on the  
8 right, if we had a radical reduction in the cost of solar  
9 PV. And what you see is that the high DG case, which I  
10 won't say towers above the base case in -- with our base  
11 case assumptions -- or the high DG case towers above the 33  
12 percent reference case with our base case assumptions,  
13 they're more or less even when we put those assumptions in.

14 So that's something that again where we would want, as  
15 we see are these changes occurring, is the optimistic case  
16 materializing, do we want to shift more in the direction of  
17 solar PV.

18 Okay, final part of this study was really an effort at  
19 synthesis and really more a piece of policy analysis, and is  
20 really aimed to a large extent at the legislative members  
21 who are engaged in drafting the 33 percent RPS legislation.

22 And what we've done here is to take these four  
23 different cases that we examined for going to 33 percent RPS  
24 and, you know, really, quite frankly I would say crudely and  
25 somewhat subjectively rated them on a pretty simple scale of

1 kind of high, neutral, or low, or who are neutral in terms  
2 of their performance along a number of dimensions that have  
3 been articulated at various stages in time as important  
4 aspects at an RPS program, or things that we -- policy goals  
5 for the RPS program.

6 And I'm sure people will disagree with some of the  
7 ratings here. But the main point here is that there's no  
8 dominant case, none of these cases is, you know, comes up  
9 cherries, or three bars across the screen. Every one of  
10 them has shortcomings on some dimensions that are important  
11 to Californians or California's leadership.

12 And what the implication of that is, is that it's  
13 really important to do some kind of -- to really be --  
14 explicitly acknowledge the tradeoffs and to get some  
15 direction in the new legislation about what the priorities  
16 are.

17 So finally, I will close just by noting both the next  
18 steps, which are to incorporate the RETI conceptual  
19 transmission plans and the California ISO's renewable  
20 integration analysis, as well as the Energy Commission's  
21 once-through cooling analysis, and to wrap up this project  
22 by the end of 2009.

23 As I mentioned before, one of the key things that we'll  
24 be looking at also is really spelling out the risk  
25 management approach, building upon the suggested strategies

1 we discussed.

2 And finally I want to note that while we're eager to  
3 take questions and hear public comments today, and Jaclyn,  
4 and I believe you're staying all day long, so said they will  
5 be here to hear public comments.

6 But we will have a written comment process on this  
7 report later on in July, after the consultants have  
8 published all of their work papers, so that commenters have  
9 the opportunity to review not only the documentation in the  
10 report, but the underlying analysis that went into it.

11 So thank you and I'm happy to take your questions now.

12 MR. ALVARADO: Thank you, Dr. Ryan. I do agree with  
13 your observation that further integration -- yeah, please  
14 come sit at the table.

15 I do agree with our observation, I think further study  
16 is needed to really integrate the other policy options and  
17 consideration of different reliability, system reliability  
18 issues.

19 I was wondering, and you did reference the second phase  
20 of your study, I was wondering if you could maybe elaborate  
21 what will -- what types of additional studies we'd be  
22 considering and what will be included in that second phase  
23 of the study?

24 MS. RYAN: Well, I think the first one is that I don't  
25 anticipate, and Ann and Jaclyn can correct me if I say

1 something really egregiously wrong. But it's not my  
2 understanding that will be doing additional studies on  
3 integration, but rather that we will be integrating into  
4 this analysis further study, most notably by the ISO, but  
5 anything else that we see that relates to both the costs --  
6 you know, the costs, risks and timing associated with  
7 integration.

8       So and that's generally been our strategy here is to  
9 build as much as possible on existing work or on ongoing  
10 work.

11       MR. ALVARADO: Okay. Just one point about the costs  
12 that you've included, you did identify a band of uncertainty  
13 associated with fuel costs and probably carbon matters,  
14 under carbon matters that might shift the overall costs or  
15 the results.

16       Have you considered any other bands of uncertainty  
17 associated with the costs of the transmission lines and the  
18 individual generation options?

19       MS. RYAN: I don't believe that we did that.

20       MR. ALVARADO: Okay.

21       MS. RYAN: Oh, wait. Well, I mean only to the extent  
22 that we, for example, with the PV, low-cost PV sensitivity.

23       MR. ALVARADO: Okay, I sort of bring it up just to lead  
24 into another workshop we're going to have on July 22<sup>nd</sup>, where  
25 we are -- the staff is engaged in an effort to update the

1 levelized cost of generation estimates. And in this effort  
2 we're trying to come up with a band, a wider band of  
3 uncertainty variables to come up with a range of levelized  
4 costs.

5 And we're also taking it one step further to examine  
6 the costs of -- the potential costs of the generation in the  
7 future, the future years.

8 MS. RYAN: Well, I think, I mean that's something that  
9 we would definitely want to look at. I'm not sure at this  
10 stage if we could actually put in a model and turn the  
11 crank, but we could certainly be in, I think, a position to  
12 discuss the implications of that in the final report. So we  
13 would welcome that work. And there's certainly a lot of  
14 uncertainties about what these variable technologies will  
15 actually end up costing, both to build and to operate.

16 MR. ALVARADO: Definitely.

17 MS. TEN HOPE: I was having a sidebar conversation, I  
18 think I missed something. I just wanted to make sure that  
19 the DG scenario did include the reduction in transmission  
20 costs; correct?

21 MS. RYAN: Yes. I'm getting nodding heads from the  
22 experts.

23 MR. ALVARADO: I do think the high DG cases is pretty  
24 insightful and I do think there's probably numerous steps to  
25 try to make that reality. Is the PUC planning on engaging

1 in any further analysis about what steps it will take to  
2 make this DG future a reality?

3 MS. RYAN: I'm getting nodding heads.

4 (Laughter.)

5 MS. RYAN: I should have brought my magic eight-ball  
6 with me. Yes.

7 MR. ALVARADO: You're welcome to come up if you want to  
8 elaborate.

9 MS. RYAN: I'm very pleased to introduce Jaclyn Marks,  
10 with the Energy Division, who will probably give much better  
11 and more thoughtful answers to all of your questions.

12 MS. MARKS: Well, not to get into the weeds, because we  
13 haven't actually identified all of the next steps, but we  
14 would like to do some type of similar implementation  
15 analysis on the high DG case to see what's feasible and what  
16 are the implementation barriers, similar to what we did for  
17 central station generation.

18 MR. ALVARADO: Okay.

19 MS. RYAN: I will mention, one of the things that we  
20 discussed among ourselves extensively, after reviewing  
21 earlier drafts of this report, is that DG analysis, the  
22 level of penetration that it contemplates is based on  
23 essentially a study of technical potential. You know,  
24 satellite mapping of rooftops, and spaces around substations  
25 and so on, and so forth, so trying to get a sense of just

1 how many places are there to put panel.

2 But you all have already raised the question of, well,  
3 what are the implications for grid integration.

4 The other thing is that sooner or later you start  
5 putting panels in places where people are not, you know, of  
6 the early adapter mindset and I think it becomes  
7 progressively -- it may become progressively more  
8 challenging to reach some of those spaces. And I think  
9 that's an example of something that we'll like to think  
10 about more and it will take different strategies to reach  
11 out further.

12 But it's worth investigating because we may not really  
13 want to have that in our hip pocket.

14 MR. ALVARADO: Okay. I also noted that as one of the  
15 metrics for considering the replacement of the once-through  
16 cooling plants and adding of any other fossil fuel plants,  
17 you are using a 17 percent planning reserve margin; is that  
18 correct?

19 MS. RYAN: Yes.

20 MR. ALVARADO: I was just wondering if there's any  
21 consideration about what would be the more adequate planning  
22 reserve margin? I think we've discussed that a little bit  
23 this morning, we've used a 15-percent planning reserve  
24 margin, 17 percent small margin, but it does increase --

25 MS. RYAN: Right.



1 MR. ALVARADO: -- the generation totals.

2 MS. RYAN: Well, two comments, and I guess we generally  
3 shoot for 15 or 17 percent. And, you know, maybe it might  
4 have made more sense as a baseline assumption to split the  
5 difference and shoot for -- you know, use 16.

6 But I'm not sure that for the way that we've primarily  
7 framed the results, I'm not sure the choice of the planning  
8 reserve margin would make that much of a difference because,  
9 again, it's the incremental cost of the 33 percent renewable  
10 cases relative to the 20 percent case, and as long as you  
11 hold the planning reserve margin constant across all the  
12 cases that you examine, then I don't think it should really  
13 matter very much to the bottom line, you know, as we've  
14 framed it.

15 MR. ALVARADO: Okay. Commissioner, do you have any  
16 other questions?

17 COMMISSIONER BYRON: A couple, if I may, two things.  
18 First of all, I think the study's very helpful and I  
19 congratulate you all on this work. And, of course, I think  
20 it's going to inform policy-makers in a substantial way  
21 going forward.

22 A couple of things that I caught, that I wanted you to  
23 elaborate on, Dr. Ryan, shouldn't we assume from this study  
24 that we ought to be over-shooting on both generation and  
25 transmission?

1           And how do we communicate this concept that there are  
2 going to be certain sites that aren't going to be approved?

3           MS. RYAN: I mean, I think that is a logical conclusion  
4 that you can draw from this study is that because  
5 essentially the lead time to respond -- the time frame in  
6 which you find out that something, that a resource doesn't  
7 pan out is wide enough, and the lead time to change course  
8 and respond is long enough that if the paramount  
9 consideration is given to 33 percent on time, in 2020, then  
10 the implication of that is that we have to build in a margin  
11 of error.

12           And maybe what we need to do is think about the optimal  
13 way to name -- the optimal name for that strategy.

14           COMMISSIONER BYRON: Right.

15           MS. RYAN: But we certainly need some degree of  
16 flexibility there.

17           COMMISSIONER BYRON: It's going to be very difficult.  
18 As Mr. Kelly came forward, and I think you can tell that we  
19 want to take a minimalist approach in terms of environmental  
20 impact, in terms of the number of transmission lines that  
21 are needed.

22           MS. RYAN: Right, uh-hum.

23           COMMISSIONER BYRON: But yet over-shooting on those  
24 that we're going to go after from a permitting perspective.  
25 How do we communicate that? It's going to be tough.

1 MS. RYAN: Yeah, and I agree it will be difficult.

2 COMMISSIONER BYRON: The other thing that I wanted to  
3 ask you about was the business-as-usual case. I forget what  
4 you called it, the all-gas --

5 MS. RYAN: The all-gas case.

6 COMMISSIONER BYRON: Does that include, you know,  
7 any -- what's it include? The carbon matter, does it  
8 include carbon capture sequestration? How does that case  
9 meet the GSU reduction goal for the electric cycling?

10 MS. RYAN: It doesn't. It doesn't.

11 COMMISSIONER BYRON: And what happens when we put in  
12 some cost or assumptions for that?

13 In other words, there may be a cheaper alternative here  
14 than building out renewables; did we look at that?

15 MS. RYAN: Right. Actually, did you all put the  
16 greenhouse gas emissions allowance and costs into that 20 --  
17 the all-gas case; do you know?

18 We'll have to look at that. But I mean, I think that's  
19 something that we make sure we clearly spell out is, you  
20 know, if we go -- if we just say we're going to go in every  
21 direction, we're not going to use the RPS, then what are the  
22 costs to electric sector if we don't do that.

23 That's a good question, Commissioner. I'm sorry I  
24 don't have a better answer.

25 COMMISSIONER BYRON: Well, like I said, I think it's a

1 good study, there's a lot here.

2 I'm going to keep my questions brief, but I think your  
3 study of military history and logistics will serve you well  
4 as you bring this report forward.

5 (Laughter.)

6 MS. RYAN: Well, I hope that nobody shoots at me. But  
7 I do believe that we're in a war against time so that we  
8 have to be, you know, very clever in how we pursue it.  
9 Thank you.

10 COMMISSIONER BYRON: Are we losing you here, now?

11 MS. RYAN: You're losing me unless somebody else has  
12 something to ask me.

13 MS. TEN HOPE: I have one question.

14 MS. RYAN: Okay.

15 MS. TEN HOPE: Do you know what's driving the  
16 difference in the net short between the RETI assumptions for  
17 the gigawatts hours, which is somewhere around 60,000, and  
18 this at 75,000?

19 MS. RYAN: I don't, but we're digging into it because  
20 we agree that these differences need to be reconciled.

21 COMMISSIONER BYRON: Yeah, I don't know, but I would  
22 imagine that it might have to do with the starting point as  
23 well, which forecast you're using.

24 MS. RYAN: Uh-hum. So we'll get to the bottom of that  
25 and our staff are already working on it.

1 MS. KOROSSEC: Commissioner Byron, with your indulgence,  
2 I'd like to check and see if Commissioner Levin may be on  
3 the phone, again, if you don't mind?

4 Commissioner Levin, are you with us?

5 COMMISSIONER BYRON: There's something surreal about  
6 that; isn't there?

7 MS. RYAN: It would be real surreal if she -- a ghostly  
8 voice.

9 COMMISSIONER BYRON: Dr. Ryan, thank you. I think Dr.  
10 Ryan needs to go, but I'm really pleased that you've left us  
11 Ms. Gillette and Ms. Marks to answer any further questions  
12 that might come up.

13 MS. RYAN: As you can see, they do it well. Thank you.

14 MR. ALVARADO: Well, maybe we should move onto Mr.  
15 Hawkins. You do have a presentation to give, too.

16 MR. HAWKINS: Good morning, Board and Commissioners.

17 The ISO basically -- first of all, it's basically  
18 picking up the baton from all the previous studies that  
19 you've been hearing about. And so our goal is to go from  
20 the 20 percent renewable studies that we have been working  
21 on to now going to this 33 percent, and that includes all  
22 the operational issues of regulation, load-following, you  
23 know, clean operations, over-gen issues and so forth.

24 But in addition to that, we're also doing work on  
25 cooperation with other balancing authorities, looking at the

1 study that was mentioned earlier.

2 How to do interchange scheduling on different  
3 timelines, do we do dynamic transfers? How much regulation  
4 burden do we pick up if we do dynamic transfers, and all of  
5 that?

6 And then what are the performance expectations that  
7 we'll get from the different resources?

8 Finally, we are working on energy storage, not only  
9 just for ancillary services, but also for the energy  
10 markets. What happens if you do the energy shifting? How  
11 big of an energy resource do you need, where do you need it,  
12 and what else can you do with it?

13 We're also then looking at non-generation resources,  
14 both energy storage and demand response as part of our  
15 ancillary services type markets.

16 Finally, the other thing is, of course, looking at what  
17 can we do to enhance our transmission system, the existing  
18 transmission, and make better utilization of that for moving  
19 all the renewable energy.

20 So we're picking up from the CPUC's cases, also adding  
21 in the high solar generation.

22 We also have engaged Nexant to help us with these  
23 studies, and so we're picking up from the work that they've  
24 already done and building on that.

25 And again, using the expertise from the utilities, as

1 well as other stakeholders to create a much more complete  
2 portfolios of what the wind, and solar, and different types  
3 of solar can do.

4 This is kind of a picture of the overall study process.  
5 It's still in draft form. But basically it's to create a  
6 lot of detailed information that we can use for our  
7 operating type studies, and looking at things as much as  
8 ten-minute type data, and one-minute type data.

9 Going at the wind -- excuse me, the load-forecast error  
10 issues, as well as the wind and solar forecast issues,  
11 trying to improve those.

12 And again, matching up our load forecasts with the CEC  
13 load forecasts and then having, basically, a step one/step  
14 two type of approach.

15 Our goal is to complete, basically the step one type  
16 piece of the study by the fall of this year, so we can hand  
17 the results back off to the CPUC with their studies.

18 A lot of work to do on the profiling and, as I said,  
19 this is very data-intensive type work, so there's a lot of  
20 work to do to create all of these generation profiles and  
21 then synchronize all of the data.

22 And so that one of the things to be done, of course, is  
23 to make sure that the data that you pick you end up -- as  
24 you escalate different years forward that you end up with a  
25 Saturday load profile that matches the generation Saturday

1 load profile, and so forth as you build and synchronize  
2 these things for the future.

3 We're also using data from NREL to look at building out  
4 more of the solar information and looking at other sites  
5 within the west. Again, I think Mark Minick, the work that  
6 they've done at Edison, and that original study then is what  
7 we're building on from that.

8 And then, of course, we're looking at what sites do we  
9 use, what analysis to do next.

10 The wind sites are basically those that have already  
11 been identified and then the next step is, of course, using  
12 a lot of the data that we already have on what the wind  
13 generation looks like for those, and so we have pretty rich  
14 datasets that will help us, I think, do both diversity  
15 studies and the prediction of what the wind will do on a  
16 very short term basis.

17 The solar is much more of a challenge and, again, we  
18 have very little in the way of -- just 400 megawatts or so  
19 of solar installation, of the concentrated or the -- yeah,  
20 concentrated solar type.

21 So now we'll have to use other types of resources in  
22 order to make the predictions of those. And this is  
23 probably the biggest risk and where the modeling studies are  
24 going to be the most challenging.

25 And so then, of course, what we have to do is to



1 synthesize all these data into fairly comprehensive models,  
2 and then from that to make sure that we've got issues about  
3 inertia and everything else covered as part of doing our  
4 operating studies.

5 And so finally, what our timeline looks like is we  
6 expect to finish our studies on 20 percent by July.

7 And then for the 33 percent, we'll have our first  
8 preliminary results basically late September, early October.

9 And then our expectation is, like most of the reports  
10 that are done, it takes you another two months to edit and  
11 write the detailed report that you can finally publish. So  
12 we hope that two months is enough to hit the December  
13 timeline.

14 And of course once you have done the preliminary work  
15 and so forth, there's always continuing work to go on for  
16 the next piece of it, so we expect to see the work  
17 continuing on well into 2010.

18 And we also expect the non-generation resource piece,  
19 to actually have the energy storage piece in operation, we  
20 hope, by the first quarter, second quarter of next year for  
21 the ancillary services market.

22 There's a lot of software changes that have to be made  
23 and potentially some market changes to make that actually  
24 happen.

25 So that's basically our overall timeline.

1       The one question I thought that was interesting was the  
2 distributed generation case. One thing that is of interest  
3 is with the work that's going on back on the East Coast, at  
4 Public Service Electric and Gas, which is looking at putting  
5 up a hundred thousand solar panels on pole tops, and the  
6 utility would own them, and the utility would actually have  
7 communication to talk to the inverters, and turn on/turn off  
8 the inverters and do various things as part of that.

9       And so if we're looking at a strong or a large  
10 distributed generation resource, that might be an  
11 interesting way to go, at least a project worth watching.

12       MR. ALVARADO: Thank you, Mr. Hawkins. I do think that  
13 these types of analysis, since it's very important to  
14 consider the operational aspects of integrating any amounts  
15 of renewable generation.

16       I did note that the renewable net short that you're  
17 using for the study is the 75,000 gigawatt hours.

18       MR. HAWKINS: Yes.

19       MR. ALVARADO: Per year. And I wonder if you will be  
20 considering other levels, scenarios, considering -- like,  
21 for example, the Energy Commission study does use a very  
22 different net short estimate?

23       MR. HAWKINS: Well, one of the risks of course is that  
24 the capacity factors may not be totally realized. And so if  
25 you think you're going to get 37 percent from wind

1 generation and it turns out to be 34 percent, you know, what  
2 is the margin that you're short and what else do you have to  
3 do?

4 And so I thought the question and answer was  
5 particularly adept as to how much extra margins you build  
6 in, or how do you handle some of those risks?

7 The recent numbers that I was doing, looking at what  
8 the load project is, certainly as we're looking at a five  
9 percent reduction in overall megawatt hours this year, load,  
10 so if you assume that the economic level of the State has  
11 declined that much and then you start building up towards  
12 2020, instead of coming out with a hundred -- or I think you  
13 had 102 terawatt hours, my numbers came out about 90  
14 terawatt hours.

15 So we probably can look at a variety of what gets you  
16 there with what are the numbers to shoot for, and what other  
17 kind of planning reserve margin you might need then?

18 MR. ALVARADO: Okay, and how about the consideration of  
19 once-through cooling plants and I think there are varying  
20 assumptions in terms of what plants may retire, or need to  
21 be replaced, but I do think it probably is an important  
22 aspect in terms of the integration?

23 MR. HAWKINS: Yes, we totally agree. The once-through  
24 cooling plant is certainly -- the expectation is that even  
25 plants that are going to be repowered probably will go off

1 line for a period of time.

2 So as you get to the build-out of 2015, 2016, and start  
3 to see some of the western cooling plants actually go away,  
4 that's going to make an interesting part of that scenario.

5 So yes, I think we'll follow the work that has been  
6 done and, you know, add onto that as to what we think the  
7 expectation will be.

8 MR. ALVARADO: Okay. Commissioner, do you have any  
9 questions?

10 COMMISSIONER BYRON: A couple. Thank you, Mr. Hawkins,  
11 for being here.

12 MR. HAWKINS: Yes.

13 COMMISSIONER BYRON: We look forward to seeing the  
14 results from the study.

15 But with regards to Mr. Alvarado's question just now,  
16 does it really make much difference whether retiree power,  
17 once-through cooling plants, on looking at going to these  
18 higher levels of renewables? Because you're going to do it  
19 anyhow.

20 MR. HAWKINS: Yeah, right, I would agree with you. The  
21 only difference was what the sequencing is and whether or  
22 not you'd lose some of the added ramping capability and  
23 regulation capability of some of these units during that  
24 middle period, the transition period, where we're going from  
25 2012 up to 2020.

1        So if you're in 2015, 2016, 2017 and you've lost some  
2 of these during that period, the question is do we end up  
3 with a larger risk because we'll have some of those  
4 resources not available during that period?

5        So I think we need to look at each year incrementally,  
6 as well as what the final target is.

7        So the final target may be fine, it's just getting  
8 there may be the risk.

9        COMMISSIONER BYRON: You know, the ISO's been a great  
10 participant in the RETI process, and that's one of many  
11 different, say, transmission planning functions that are  
12 underway.

13       And we heard earlier about the utilization of existing  
14 right-of-ways and transmission and, yet, isn't that  
15 difficult to do? I mean, it's like -- it's like the Bay  
16 Bridge right now is under construction to be replaced but,  
17 you know, we're building it alongside the existing Bay  
18 Bridge because we'd like to have the road in service while  
19 we're changing out what those right-of-ways are currently  
20 used for.

21       I'm sorry, I'm mixing my analogy here.

22       MR. HAWKINS: It's a pretty good analogy, though.

23       COMMISSIONER BYRON: But how do we do that? Do you  
24 believe that we can utilize existing right-of-ways in a  
25 substantial way and figure out how to do that from a

1 reliability perspective?

2 MR. HAWKINS: That's going to certainly be a real  
3 challenge. Because in order to take the lines out of  
4 service to do the rebuild there certainly is a period of  
5 time -- you know, can you get the outages and how long will  
6 it take to do the rebuild?

7 Because often you're going to have to change the  
8 towers, as well as just the lines, so I don't know the  
9 details of that kind of a transmission issue, but that's a  
10 good question.

11 COMMISSIONER BYRON: Will your study get into that  
12 level of detail?

13 MR. HAWKINS: I assume that we would. That's something  
14 that a transmission plan would have to look at.

15 The other issue we discovered is that just getting the  
16 outages is no small feat, in order to take those kind of  
17 lengthy outages.

18 Yet, you know, as an analogy I guess, we did take a  
19 fairly extensive outage a couple of years go to do the  
20 replacement of the inverters on the big, high-voltage DC  
21 line, so that was done both at Bonneville and at L.A.

22 So it's possible to take these lines out and do these,  
23 so it's not like it's impossible.

24 COMMISSIONER BYRON: Well, I think you know we're  
25 counting on the ISO to figure out how to be able to do that.

1 But let me ask one last question, how are you  
2 addressing the non-ISO control areas in your study? Are you  
3 including them?

4 MR. HAWKINS: As far as I know, that from the  
5 operations perspective what we're trying to do is a region-  
6 wide study.

7 In terms of the transmission planning, I think Mr.  
8 Deshazo has been trying to include them as part of the  
9 overall RETI process and all that.

10 But in terms of the overall operations pieces, we've  
11 been mostly -- yeah, we've talked to, certainly with SMUD  
12 and planning with them.

13 We haven't had, I don't think, as much contact with  
14 L.A.

15 COMMISSIONER BYRON: Well, let me ask it differently  
16 then; are you limiting the results of your work to the ISO-  
17 controlled areas at this time?

18 MR. HAWKINS: Yes.

19 COMMISSIONER BYRON: Okay, thank you.

20 MR. ALVARADO: Okay, how about if we move along, we can  
21 open the panel up for public discussion in a while.

22 But next we have Ms. Tanghetti, with the Energy  
23 Commission staff.

24 MS. TANGHETTI: Good morning. I'm Angela Tanghetti,  
25 and I work in the Energy Commission's Electricity Analysis

1 Office.

2 And I want to share with you today some of the more  
3 interesting input assumptions and findings included in our  
4 recently posted Joint Renewables Office and Electricity  
5 Analysis Office staff report.

6 The staff in these two offices began this IEPR cycle  
7 trying to understand where the CEC could add value to any of  
8 the debate surrounding the 33 percent RPS Executive Order.

9 And our initial study was to focus on the type and  
10 timing of proxy generation that might be needed to back up  
11 or firm up different mixes of intermittent generation.

12 That is, would large amounts of wind development  
13 require different types of proxy generation additions, than  
14 similar quantities of wind development.

15 However, once we began our work to kind of quantify the  
16 input assumptions necessary for this type of analysis, the  
17 focus of where staff thought value could be added to this  
18 debate kind of evolved.

19 Once we realized the potential magnitude of all the  
20 scoping plans, electricity resource goals, taken together  
21 with a sample OTC compliance path, the focus of the study  
22 really evolved.

23 But first, when I mention the scoping plan, I'm  
24 referring to the Air Resources Board Climate Change Scoping  
25 Plan for the year 2020.



1        In this plan, goals for the electric generation sector  
2 are outlined, again for the year 2020. And 33 percent  
3 renewable energy standard is a key electric sector strategy  
4 in the scoping plan.

5        However, the other electric sector strategies contained  
6 in this scoping plan may have just as large an impact in the  
7 electric sector as 33 percent renewables.

8        So this is why we're attempting to study all the  
9 electric sector strategies outlined in the scoping plan.

10       Also considered again in this analysis is a sample OTC  
11 compliance path for some form of replacement or retirement  
12 of California's electric generators that use once-through  
13 cooling.

14       So again, our study evolved from the type and timing,  
15 understanding the type and timing of generation resources  
16 that may be needed to firm up or back up intermittents, to  
17 assessing the consequences of adding scoping plan resources  
18 and a sample OTC compliance path on the incremental amount  
19 of renewables, also known as net short, needed to achieve a  
20 33 percent target, and also on the remaining system need for  
21 any capacity of energy.

22       We also tried -- we also assessed if there was a  
23 substantial difference between the performance of the  
24 existing natural gas-fired unit between a high solar or a  
25 high wind view of the 33 percent future.

1           And also, we looked at would improving the consistency  
2 of our load and wind hourly characterizations reduce any  
3 modeling uncertainty?

4           And could exogenous consideration, that is outside of  
5 any simulation model of local transmission and generation  
6 constraints yield useful information on the performance of  
7 any new natural gas-fired units.

8           So with these questions in mind, our office staff, with  
9 the help of the renewables office, developed three cases of  
10 the future WECC-wide generation development for the years  
11 2012, 2016, and 2020 to test in some type of production cost  
12 model.

13           So let's see, this is an interesting slide. So again,  
14 the focus years for the study are 2012, 2016, and 2020.  
15 However, for this comparison purposes, the values shown on  
16 this table here are only for 2020.

17           First, the assumption that's common to all cases is  
18 this sample OTC compliance path, that last green column over  
19 there on the right.

20           And in it, you'll notice that 12,655 megawatts were  
21 retired and about 7,700 megawatts are added back into the  
22 system.

23           So this 5,000 megawatts, basically the difference  
24 between the 12,000 and 7,000, are un-replaced generation,  
25 and that's possible because of a combination of assumed

1 transmission upgrades, and then there's also generators that  
2 are located in areas with no local capacity requirements, or  
3 that generators, if retired, didn't violate local capacity  
4 requirements.

5 The reference case considers only the sample OTC  
6 compliance path and a 20 percent RPS by 2012.

7 Also, for those not familiar with the term "net short"  
8 in this context, it refers to the amount of renewables  
9 needed to achieve the maximum RPS target, less the amount of  
10 any existing renewables.

11 So again, the net short in the 20 percent case is about  
12 29,000 gigawatt hours. And then in the cases two and three,  
13 with the 33 percent renewables, it's about 45,000 gigawatt  
14 hours.

15 Again, that's in contrast to what the PUC findings  
16 showed as about 75,000 gigawatt hours of net short. So  
17 again, it's a significant difference.

18 And what's driving those are the complementary programs  
19 from the scoping plan. That is the complementary programs  
20 of energy efficiency and rooftop PV.

21 So when those complementary programs are combined, they  
22 can account for generation savings, as much as generation  
23 savings as a 33 percent renewable. So again, it's an  
24 important consideration.

25 So this is basically just to outline the different

1 assumptions and how they vary between the cases.

2 The next slide is just what I want to show here is the  
3 total generation, the total RPS generation by case that we  
4 looked at.

5 Again, the case one is again a 20 percent RPS by 2012  
6 and, again, these values are for 2020. But what that  
7 equates to is, again, the total amount of renewables in that  
8 year is about 61,800 terawatts. And in this case the net  
9 short with -- again, was at 29,000

10 So what this is trying to show you here is the total  
11 RPS mix by case.

12 Again, the total RPS generation in cases two or three  
13 are the 78,000 terawatt hours, with a net short of about  
14 45,000 terawatts in those cases.

15 The case one reference case reflects California's  
16 current procurement path. So that is with the current --  
17 the way the system's currently being built out, you're going  
18 to see mostly geothermal, with the remaining filled in,  
19 wind, solar, biomass, small hydro.

20 And even though we named cases two and three high wind  
21 and high solar case, geothermal and biomass fuels still  
22 played an important role in these 33 percent cases.

23 Let's see, so the key drivers in this analysis are the  
24 study years are important, mainly for comparison purposes.  
25 For example, when we present amounts of non-renewable

1 capacity additions for the year 2020, we're beginning from a  
2 base year of our study, which is 2012.

3 Our study assumes that no generation additions for the  
4 period prior to 2012 are already part of the existing  
5 generation and not new generation additions.

6 So just as an example, generation additions between the  
7 years 2009 to 2012 are forecasted to be about 5,000  
8 megawatts.

9 Second, the amount of combined heat and power included  
10 in the scoping plan, staff assessed, is assumed to be all  
11 gas-fired and must take for this study.

12 A large portion of CHP host sites are located in  
13 Southern California.

14 Siting this level of gas-fired CHP might be difficult  
15 in light of the scarcity of emissions credits for this  
16 region.

17 And third, the sample OTC compliance path we used was  
18 predominantly combined cycles. More simple cycle additions  
19 may yield different results.

20 Another key driver in the study is the energy  
21 efficiency profiles. We had put hourly profiles in our  
22 simulation study and they were mainly targeting at lighting  
23 programs, with remaining savings from refrigeration and air  
24 conditioning programs.

25 Yes, we did model EE on the supply side in the

1 simulation model. Since the scoping plan's goals for EE are  
2 above what was already included in the IEPR '07 demand  
3 forecast.

4 So this was one way to include a significant impact on  
5 natural gas use for electric generation in our simulation  
6 model.

7 But not only does EE impact electricity consumption,  
8 but based on this hourly profile of lighting programs, air  
9 conditioning and refrigeration, it does impact the peak  
10 demand as well.

11 So when you impact the peak demand either through this  
12 rooftop PV or EE, you impact the calculation of planning  
13 reserve margin and the need for any new generation.

14 Also for this study, Energy Commission staff developed  
15 a method to create internally consistent hourly load and  
16 wind shapes. And staff used the same algorithm to create  
17 both the hourly wind and hourly load shapes.

18 And this method uses actual wind generation and actual  
19 load data to create an internally consistent synthetic  
20 annual wind and load shapes.

21 So if you want more information about that, I'm not  
22 going to go into it now, but you can find the detail in our  
23 report, and I also added contact information at the end of  
24 this presentation.

25 So what's interesting as far as -- this amount. This

1 1,910 megawatts of new generation additions between 2012 and  
2 2020. We think that's interesting because 1,900 megawatts  
3 of generic, non-renewable generation addition was added to  
4 the reference case between those two years in order to meet  
5 a -- we did a 15 percent planning reserve margin by control  
6 area. So we didn't do it statewide, we did it by control  
7 area, and the control areas for California, the ISO, L.A.,  
8 SMUD, TID and IRD.

9 So what what was our criteria for adding new,  
10 nonrenewable generation?

11 For the reference case, case one, renewables are added  
12 in each study year to meet a 20 percent RPS target.

13 Staff did develop a sample OTC compliance pack that  
14 considers transmission upgrades, local capacity  
15 requirements, and a really simplified consideration of  
16 inertia requirements in Southern California.

17 And so for each control area in California and actually  
18 the rest of the WECC, a 15 percent planning reserve margin  
19 is enforced by either -- by adding either proxy simple cycle  
20 or a combined cycle generation.

21 Again, a common thread to all three cases is the sample  
22 OTC compliance path and a 15 percent planning reserve  
23 margin.

24 For cases two and three, resource planning development,  
25 renewables added were added in each year that phased up for

1 the 33 percent by 2020.

2 Also phased in were the scoping plan goals for combined  
3 heat and power, and this equates to about 4,500 megawatts of  
4 dependable capacity by the year 2020, just for the combined  
5 heat and power goal.

6 For the scoping plan energy efficiency, that was also  
7 phased into the year 2020 and this equates to about 6,000  
8 megawatts of peak reduction, if you're looking at the hourly  
9 profile we used for that.

10 And again, resource plan development is done  
11 exogenously to any simulation tool, so we just make these  
12 calculations before we do any simulations.

13 So once we do input all these resource plan  
14 assumptions, once we build those into our simulation tool  
15 what can we find that's interesting?

16 And in the past, one of the first simulation results we  
17 always examine are capacity factors. So specifically we  
18 wanted to look at the capacity factors of the once-through  
19 cooling additions, since we thought these were of interest,  
20 because they're one of the few dispatch able resources we  
21 have in the simulation tool for California.

22 For the reference case, the OTC replacement capacity  
23 factors are what we considered to be, today, in an expected  
24 range.

25 The capacity factor is shown for the combined cycles in



1 cases two and three, again with the higher penetration of  
2 renewables and other scoping plan goals trend much lower.

3 What's the right capacity factor for combined cycle in  
4 the future?

5 Based on research and gut feeling, 60 percent seems  
6 plausible.

7 However, we have historically seen some capacity  
8 factors in the 20 to 40 percent range and those units are  
9 still in operation today.

10 So are these capacity factors too low? More than  
11 likely if one assumes the generation owners are finding  
12 revenue only in the energy market, and this may not be the  
13 case by the year 2020.

14 And again, this is where we think an area of further  
15 sensitivities is needed.

16 We did complete some simple sensitivities, where we  
17 kept the total amount of once-through cooling replacement  
18 the same, just changed the ratio of the simple cycles to the  
19 combined cycles, and the capacity factors did approved for  
20 the year 2020 for cases two and three. However, only by  
21 about ten to 20 percent so, correspondently, a simple cycle  
22 capacity factor is dropped as well.

23 So again, we think this is an area where further  
24 sensitivities are warranted.

25 Let's see. Okay, the interesting bar in this chart is

1 again this dark green one here. So I know your eyes may  
2 want to go to the purple bar, but the darker green bar is  
3 where I really intend you to focus.

4 The darker green bars are simulation results for the  
5 year 2020 for dispatchable natural gas-fired generation in  
6 California. While the lighter green, those lighter green  
7 bars right there are generation from the must-take gas-fired  
8 combined heat and power.

9 And then the purple top bar represents that EE savings,  
10 that was modeled as part of the resource mix in the year  
11 2020 so, again, that dark purple is energy efficiency.

12 This is the combined heat and power and, again, these  
13 were the differences in the dispatchable gas, and these are  
14 case one and case two, high solar, and case three high wind.

15 For many hours, in any given year, the resources in our  
16 simulation tool has available to load follow is natural gas-  
17 fired non-QF generation.

18 I'm not saying that all hours of the year, but  
19 definitely the majority of the hours in a typical year, the  
20 marginal generator is gas-fired.

21 So that's just what this chart's intended to  
22 demonstrate.

23 Natural gas use for electric generation in the year  
24 2020. Again, for this analysis the high wind case uses  
25 slightly more natural gas in California than the high solar

1 case. This appears to be intermittency-driven results.  
2 More units in California are committed and a few more  
3 dispatched under the high wind case.

4 Since more generators are committed and dispatched in  
5 California, slightly less natural gas-fired generation is  
6 needed as imports coming into California.

7 But note that these differences for case two and three  
8 are pretty insignificant with respect to overall gas-fired  
9 generation in California.

10 However, the higher penetration of EE, rooftop PE and  
11 renewables for cases two and three do impact the natural gas  
12 use for generation when compared to the reference case, not  
13 including those complementary programs and meeting the 20  
14 percent renewable target.

15 Let's see, this chart is just intended to show you how  
16 natural gas-fired generation does increase over the forecast  
17 years, no matter what case you're using. The growth is  
18 definitely more modest from 2012 to 2020 for cases two and  
19 three but, nonetheless, this is just to show that natural  
20 gas use is increasing over the forecast years no matter what  
21 case you're using.

22 Let's see, so the next step. Over-generation issues.  
23 And there are possible instances of over-generation in our  
24 simulation results. And over-generation, how we're defining  
25 it, is a condition where more generation is provided than

1 load is available to consume it.

2 The way we intend to quantify this is using a  
3 production cost model and on an hourly basis trying to  
4 quantify any of your baseload must-take resources are  
5 running at lower than their possible generation in that  
6 hour.

7 And also what we intend to look at, as Mark Minick  
8 pointed out this morning, is to quantify the stops and  
9 starts of your pump storage units as well.

10 The scoping plan does include goals for electrification  
11 of the transportation sector. Staff here needs to explore  
12 better the type and timing of these proposed goals to better  
13 understand how these transportation sector goals could  
14 impact the electric sector in the 2012 to 2020 time period.

15 Some contend that the impact may be small in our demand  
16 forecast, but depending on the type of electrification.

17 Again, some sensitivities. We'd like to look at  
18 simulation results for different OTC compliance paths, one  
19 with more simple cycle additions in contrast to the current  
20 sample OTC compliance path, where we definitely choose more  
21 combined cycles.

22 Nonetheless, many of the OTC plants that are poised for  
23 retirement must be replaced with local generation and  
24 transmission reliability purposes.

25 Should we characterize CHP differently? Maybe lower

1 the amount, recalculate the amounts of renewables needed to  
2 meet RPS net short if that's the case.

3 We'd like to incorporate the 2009 IEPR draft demand  
4 forecast, the impact on the amount of new renewables and,  
5 ultimately, natural gas used for electric generation.

6 And based on other IPO work, we may want to adjust the  
7 hourly profile for EE. Also, when we do incorporate the  
8 2009 IEPR forecast, we need to ensure that any EE from the  
9 scoping plan is now not double counted in our demand  
10 forecast, as well as rooftop PV.

11 So those are some of the next steps and sensitivities  
12 we'd like to do for this analysis.

13 And also, again, it was a joint Renewables  
14 Office/Electricity Analysis Office report. So if you do  
15 have questions on the renewable portfolios, again, I've  
16 tried to provide some contact information here. And also,  
17 the report can be found at that URL, if you haven't yet  
18 looked at the report yet. Okay.

19 MR. ALVARADO: Thank you, Angela. I do think that some  
20 of the assumptions that Energy Commission staff did include  
21 in this study are somewhat different from some of the other  
22 studies that we've found from the ISO, the utilities, and  
23 the PUC, so I do think it does suggest that further,  
24 additional studies or investigations are needed, working  
25 together with the other parties.

1 I really don't have any questions but, Commissioner, do  
2 you have any questions for Ms. Tanghetti?

3 COMMISSIONER BYRON: Ms. Tanghetti, just a couple of  
4 quick questions. Obviously, on net short, assuming the  
5 Energy Commission's analysis is a lot less than the others  
6 that we've seen today, and I assume that's based on a  
7 revised forecast they didn't have access to?

8 MS. TANGHETTI: The differences mainly in the net short  
9 are, again, a revised forecast of existing generation. I  
10 noticed in the PUC report it was about 27 terawatts. What  
11 we assumed for existing renewables by the end of 2008 is  
12 about 32.5 terawatt hours, so that's 5,000 terawatt hours  
13 difference, which is a large amount.

14 And some of that could be attributed to we include the  
15 POUs, out-of-state renewables as existing as they are now.  
16 So again, the starting point is different, you're correct.

17 And inclusion of the complementary programs, when you  
18 include significant amounts of EE, rooftop PV, and combined  
19 heat and power that lessens your amount of retail sales.  
20 And so the RPS is calculated based on retail sales, so that  
21 has a significant impact in that calculation.

22 COMMISSIONER BYRON: Right. Well, I don't expect an  
23 answer, but I think the question on everybody else's mind is  
24 what if we're wrong?

25 One other quick question and then I think Ms. ten Hope

1 has one.

2 I noticed as well from our work that not much --  
3 there's not much natural gas usage reduction as we go  
4 through the years and, therefore, there's not much GHG  
5 reduction either from the renewable cases; correct?

6 MS. TANGHETTI: Correct.

7 COMMISSIONER BYRON: And as you indicated, natural gas  
8 use will continue to rise over the years regardless of what  
9 scenario you're looking at.

10 So where's the tradeoff. What's the benefit of moving  
11 to renewables if we don't reduce GHG?

12 MS. TANGHETTI: Diversify your portfolio. But again,  
13 it's all driven a lot by our assumptions of energy  
14 efficiency which, again, lessens your amount of renewables  
15 that you're adding to the system.

16 So it's kind of a tradeoff there. Another assumption  
17 is that the combined heat and power outlined in the scoping  
18 plan, we're assuming that to be all natural gas. There are  
19 options for lessening natural gas use in there.

20 So if you do increase the amount of renewables and  
21 assume that less of a combined heat and power is gas-fired,  
22 again you're going to be maybe on a flatter growth of  
23 natural gas demand but, nonetheless, not as much of an  
24 increase as you see in just the 20 percent case.

25 So it does have an impact if you look at those overall

1 charts on gas use.

2 COMMISSIONER BYRON: Thank you.

3 MS. TANGHETTI: Sure.

4 MS. TEN HOPE: I just wondered, this current net short  
5 use is the '07 load forecast; is that correct?

6 MS. TANGHETTI: Correct.

7 MS. TEN HOPE: So we would expect this to go down to  
8 the more updated for '09?

9 MS. TANGHETTI: It depends on the ratio of the  
10 additional EE in the new demand forecast. It looks like  
11 there is a significant portion, as you get out in the  
12 future, is economic driven, but a portion of it is also  
13 energy-efficiency driven. So we might not be lowering our  
14 amount of renewables net short by as much as one would  
15 think. We don't want to double count those.

16 MS. TEN HOPE: And then I think you said one of the big  
17 differences between this net short and the PUC study was the  
18 assumptions about energy efficiency and meeting the energy  
19 efficiency targets in AB 32.

20 I thought that the PUC study included aggressive energy  
21 efficiency, but maybe it's the current energy efficiency  
22 goals of the PUC and not full achievement of AB 32.

23 Can you clarify which energy -- I mean, what the  
24 difference was in the energy efficiency assumptions in the  
25 two?



1 MS. TANGHETTI: I don't think I can. Can you, Jaclyn?

2 MS. MARKS: I don't have the numbers off the top of my  
3 head, but in the base case we assumed the mid-level goals,  
4 which was in the 2007 IEPR forecast.

5 And for the low-load sensitivity, we assumed full  
6 achievement of the AB 32, energy efficiency and other demand  
7 cycles.

8 MS. TEN HOPE: Okay.

9 COMMISSIONER BYRON: Thank you.

10 MS. TEN HOPE: It's still a little bit mysterious what  
11 the big difference is, though.

12 MR. ALVARADO: Given the time, maybe we can move  
13 forward to Mr. Brand. I do know Mr. Brand has a full,  
14 extensive set of slides that was also included in our  
15 website, too, that has the details of the city assumptions  
16 and results.

17 MR. BRAND: Thank you. I was going to say good  
18 morning, according to my notes, but I'll say good afternoon,  
19 instead.

20 My name's Geoffrey Brand, I'm with the Gas Market  
21 Modeling Group, with ICF International.

22 Two other principal, key members of our team are Kevin  
23 Petak and Frank Brock, and their contact information is on  
24 the slide.

25 Our study is a little different. We're not looking at

1 the electricity network, we're actually looking at the  
2 natural gas network in California and see how renewable  
3 generations would have an impact on that.

4 That does not look good. More specifically, we're  
5 looking at how variations in renewable power, mainly wind  
6 and solar, will affect gas generation and, therefore, gas  
7 consumption in the power sector.

8 Our goal was essentially to project the adequacy of  
9 California's natural gas pipeline infrastructure, the gas  
10 pipelines and gas storage in 2020 to meet a peak day  
11 requirement.

12 The natural gas system in California peaks in the  
13 winter, so looking at a January peak date in 2020, the year  
14 that the 33 percent renewable RPS standard will be met.

15 To do that, ICF modeled not only California's natural  
16 gas infrastructure, but pretty much the entire western U.S.  
17 We did this in five different scenarios.

18 The different scenarios, we have a base case, but the  
19 scenarios also varied weather conditions mainly,  
20 specifically, temperature. On a more adverse weather day we  
21 have colder temperatures and have higher natural gas  
22 utilization, and higher electricity sales amounts.

23 We also varied the amount of type of renewables mix,  
24 what proportions of solar, wind, biogas generations, and we  
25 also varied the amount of solar and wind generation

1 available.

2 For instance, if the wind is not blowing quite as hard  
3 or solar, the sun is not shining as much, essentially we  
4 would have less -- less generation available and, therefore,  
5 higher gas generation necessary.

6 The assumptions we had were actually based on scenarios  
7 we had with the Implementation Analysis Working Group, and  
8 we took those assumptions of generation mix of the various  
9 renewables.

10 We used CEC's 2007 projection for electricity demand  
11 growth, and that is about 1.1 percent a year to 2020.

12 All other natural gas assumptions are based on our own  
13 internal base case. They have the assumptions of what the  
14 other sectors, other than the natural gas market are doing,  
15 space heating for residential and commercial load, and any  
16 industrial gas demand.

17 Our natural gas pipeline and storage infrastructure are  
18 also based on our internal forecast.

19 Inside California we do not have any large amounts  
20 of -- we have no pipeline capacity additions assumed by  
21 2020.

22 We do have additional pipelines going to the border,  
23 but nothing within California.

24 We also assume storage, natural gas storage additions  
25 of two additional natural gas storage fields and one storage

1 field expansion.

2 But in general we're using pretty much the same natural  
3 gas infrastructure we have today.

4 These are our five cases. We have a reference case  
5 which kind of has the -- we meet the 33 RPS in 2020; we have  
6 the expected generation from those renewable assets; and  
7 then we assume normal weather.

8 I think I missed, for a peak day this would be in  
9 January.

10 Our second case we just look at adverse weather, and  
11 essentially we have a much colder day in January which  
12 increases both natural gas consumption and electricity  
13 sales, and we also have more adverse hydro conditions in the  
14 Pacific Northwest, which reduces electricity imports from  
15 there due to lower generation in the northwest.

16 Case three, then we assume lower solar and wind  
17 generation due to less favorable conditions at the  
18 generation sites and then we compensate that by increasing  
19 gas demand.

20 And then case four and five are similar to three, but  
21 we have a different generation mix. In case four we have  
22 more wind generation assets and in case five we have more  
23 solar assets.

24 I'm not going to spend too much on this slide, but this  
25 kind of shows the modeling process we did to reach our peak

1 day requirements, that was our final goal.

2 We have like a variety of models. GMM stands for gas  
3 market model. Essentially what that does is model the  
4 entire North American market on a monthly basis, pretty much  
5 out to 2030.

6 That is kind of necessary because gas supply and demand  
7 and regional flow throughout North America impact how much  
8 gas is available for California.

9 We take that monthly model and then that sets beginning  
10 and ending month conditions for our daily model. Our daily  
11 model shows daily gas demands and regional flows for an  
12 individual month.

13 And then finally we take those daily and monthly  
14 results and we put them in what we call RIAMS. RIAMS stands  
15 for Regional Infrastructure Assessment Model.

16 And what that is, is actually a more detailed  
17 infrastructure model just in a specific region. In this  
18 case it was the Western United States.

19 The level of detail is actually county by county, and  
20 so we have pipeline capacity going between counties and we  
21 also have individual large assets, such as storage fields.

22 So our level of detail for the study was on a county-  
23 by-county basis and a daily type from a time period.

24 This graph table shows our projected assumed  
25 electricity generation for the reference case, actually for

1 all cases.

2 As you can see, if you look at the 2008 column, we have  
3 268 terawatt hours of retail electricity sales. We have 39  
4 terawatt hours of renewables of both internally generated  
5 and imported, which equates to about 15 percent of that  
6 total electricity retail sales.

7 If we go according with the 2007, 1.1 percent down to  
8 about 300 -- I'm having a hard time reading that -- 309  
9 terawatt hours by 2020, then we have 103 terawatt hours  
10 necessary renewable sales to meet that 33 RPS standard.

11 An important part to look at this slide, look at the  
12 very top line as in gas generation, you have gas generation  
13 roughly around 120 terawatt hours in 2007 to 2008. If  
14 increasing renewable generation, you only can get around 90  
15 terawatt hours by 2020, so we see a reduction in the amount  
16 of electricity generated from gas-fired units.

17 The top table up here shows the various generation mix  
18 of the various renewables by renewable source. For the  
19 reference high, we have a high wind case and then a high  
20 solar case. Each meet the 103 terawatt hours by 2020.

21 The table below shows how we reduced it when we had  
22 unfavorable conditions for generation.

23 Wind generation, we looked at the reduction of 24  
24 percent, which is not showing up at all, sorry about that.

25 But that was mainly based -- it was sort of the

1 reduction of potentially 24 percent below was based on 30  
2 years of weather station data. So if we took the low wind  
3 year in the last 30 years, we could possibly see a reduction  
4 of 24 percent of what we'd expect to if we had a normal  
5 year, and then the solar generation with a reduction of nine  
6 percent.

7 This graph just kind of shows wind variability within  
8 the projected month of January for the reference case, from  
9 the 31 days. This is actually sorted lowest to highest, in  
10 essence because it can certainly go up and down during the  
11 month.

12 But given normal weather patterns we can see lows, just  
13 because different days have different outputs, of roughly 30  
14 gigawatt hours per day up to 150.

15 On the reduced generation case, we assumed that those  
16 amounts were reduced by roughly a fourth.

17 And for our stress case for this system, we were trying  
18 to model the natural gas infrastructure, we assumed that the  
19 coldest day appeared on the lowest wind generation day, so  
20 it would be the worst case scenario.

21 In this slide, and this kind of shows the California  
22 balance for an average annual day. The big key points here  
23 is that in 2008 California consumed an average of about 6.3  
24 billion cubic feet per day, and by 2020 that is going down  
25 to about 5.4

1        So in essence we are projecting a decline in natural  
2 gas consumption for the State of California given these  
3 assumptions.

4        The biggest drop was actually in power generation, it  
5 actually dropped about .8, or the .9 VCFD drop.

6        The other sectors, residential, commercial and  
7 industrial are essentially pretty well flat.

8        On the supply side, gas production, internal California  
9 gas production's roughly the same. Therefore, that drop was  
10 due to -- was balanced by reduced pipeline imports.

11       This is what our assumptions are, what our projected  
12 analysis came up with for gas consumption on a peak day,  
13 given normal weather. This is about 8.2 billion cubic feet  
14 per day. The average day was 5.3 in 2020. So on a peak  
15 day, the highest day of the year, you'll get about 50  
16 percent extra load.

17       The half of that load is space heating in residential  
18 and commercial sectors, while 30 percent is the power sector  
19 and about 20 percent is the industrial.

20       I apologize for the lack of clarity on the slides.  
21 They look a lot clearer on my computer.

22       This is showing a map of how the peak day is actually  
23 met. The large arrows going into the State are pipeline  
24 flows and imports. The number off the top, if you can see,  
25 I don't know if you can see that, but it says roughly 1.2



1 Bcf a day of pipeline imports up in Malin, Oregon, the  
2 northern border there. But there's about 2.2 Bcfd of  
3 capacity. So there's a fair amount of capacity available  
4 left, even on a peak.

5 Again, roughly, you have down below 2 Bcdf capacity on  
6 the Arizona border, and about 4.9 Bcdf capacity.

7 Of course, we not only modeled import sites, we modeled  
8 pipeline capacities throughout the State of California and  
9 it was adequate to meet the reference case results.

10 Storage was actually -- was draws. I think about 3.6  
11 Bcdf, 'm having a hard time reading it myself, but that's  
12 just about a little over -- a little over the 6.5 billion  
13 cubic feet per day of projected storage capacity. So  
14 there's a fair amount of additional capacity for reliability  
15 purposes, even on a peak day.

16 These are results of the other cases. Case two is just  
17 the adverse weather, if you have a much colder day than your  
18 typical, average January cold day, you will see additional  
19 1.1 billion cubic feet per day.

20 The reduced renewable generation of both wind and solar  
21 for all the cases range a little bit, but they're roughly  
22 the same, and they kind of peak at an additional half a  
23 billion cubic feet per day. So you end up with roughly  
24 around 9.8 cubic feet per day. Which is not terribly  
25 different than what we have right now.

1           And these are just a quick summary of my results. A 33  
2 RPS standard leads to a decline in gas demand in California,  
3 even under assumptions of adverse weather and hydroelectric  
4 conditions, we might consume on an average year less than  
5 what we're consuming in 2008.

6           Reduced renewable generation's not significant enough  
7 to cause potential problems with the current pipeline  
8 structure, even with that increased half a billion cubic  
9 feet per day due to reduced renewable generation.

10          And then the final point is technology mix, especially  
11 such base loads of supplies, such as geothermal, really help  
12 the -- reduce the variability of potential need for gas-  
13 fired generation.

14          And also, if you geographically move the wind  
15 generation and therefore you have a much more steadier, such  
16 that you don't have wind dying all in one place, therefore a  
17 geographical mix of both the solar and wind will also help  
18 on keeping the assumption more steady.

19          And finally, some caveats. This was based on the 2007  
20 CEC projection of 1.1 percent growth per year in California  
21 electricity load. I know there's a newer update, but if  
22 that changes, that would change the results of the study.

23          Our wind and solar variability was some estimates that  
24 we came up with. Obviously, there's some more, could be  
25 much more better detailed as more specific sites are decided

1 upon.

2 This analysis also assumes that when renewable  
3 generation was not being -- was reduced, that was  
4 essentially made up with gas generation essentially in the  
5 same spot. That might not necessarily be the case.

6 And finally, our granularity of our study was based on  
7 county level assessment. There may be more local  
8 bottlenecks that we're not covering.

9 And also, we only looked at it on a daily basis.  
10 Certainly, there might be some hourly problems that might  
11 come into affect.

12 And that is all I have, thank you.

13 MR. ALVARADO: Thank you, Mr. Brand.

14 I guess the general uptake I see is that the natural  
15 gas system is really going to be adequate. I had some  
16 questions more about the day-to-day variability, you know,  
17 if you do have a high wind case, and one day last week the  
18 wind was blowing really strong, it was a lot cooler, and  
19 then next day suddenly the wind -- a high pressure front  
20 comes in and the wind just stops.

21 Is the gas system, do you think the gas system really  
22 is going to be adequate enough to be able to take that just  
23 immediate surge need for gas generation?

24 MR. BRAND: Well, I think the biggest stress on the  
25 system will actually be on a cold January day. So if that

1 happens in the midst of January, that's most important. If  
2 it happens on a shoulder month, the pipelines can be fairly,  
3 you know, well packed with line pack and cover a lot of  
4 that.

5 So again, it's more of a -- if it comes to extremes  
6 it's local problems, but as a system as a whole it will  
7 probably be fine.

8 MR. ALVARADO: Given that some of the other scenario  
9 analysis, like the one that Angela has put together, does  
10 have sort of a different gas demand trajectory, then is  
11 there in your analysis, are you considering a point where  
12 the gas system really does become stressed?

13 MR. BRAND: Well, certainly, if you had a 1.1 percent  
14 growth in renewable generation -- I mean, electricity sales,  
15 I mean if that does not come to pass, we'll actually make  
16 this system worse.

17 Also, we have very flat residential/commercial demand.  
18 We're assuming that there are strong efficiency programs to  
19 essentially keep that demand flat, but might have population  
20 growth. Therefore, the other sectors, not the power  
21 generation sector, might grow and cause a number of  
22 problems.

23 So there's certainly uncertainties in not only the  
24 power generation, but the other sectors.

25 MR. ALVARADO: Thank you.

1 Commissioner, do you have any questions?

2 COMMISSIONER BYRON: I do. Thank you, Dr. Brand.

3 It looks as though your study is a little bit different  
4 than the Energy Commission with regard to how much less  
5 natural gas would be used with a full build out to 33  
6 percent renewables.

7 In fact, if I'm understanding figure six correctly, you  
8 show natural gas for power consumption in 2008 at about 121,  
9 I assume that's billion cubic feet. Anyhow, the relative  
10 number is 121 to 90 in 2020. I'm looking at figure six.

11 MR. BRAND: Gotcha.

12 COMMISSIONER BYRON: So that's about a 25 percent  
13 reduction, I think. I don't think we saw numbers nearly  
14 that large in reduced gas usage. Am I doing my math  
15 correctly?

16 MR. BRAND: Yeah, that is correct. Essentially, that's  
17 driven by the assumption of electricity sales of getting the  
18 103. That number was kind of fixed based on we're trying to  
19 meet the 33 percent standard.

20 And then the electricity sales of 309, which is -- that  
21 was a growth from -- of 1.1 percent per year.

22 The other large hydro, the nuclear renewal, they don't  
23 really change all that much. The gas-fired generation just  
24 dropped out of the numbers that we have.

25 So if there's uncertainty on the electricity sales or

1 the uncertainty of the -- let's see what else it would be?

2 Well, again, the 33 percent standard is kind of fixed, also.

3 COMMISSIONER BYRON: I didn't go back and look at the  
4 Energy Commission reduction. Ms. Tanghetti, do you have any  
5 comments as to why they're so different in the natural gas  
6 drop off?

7 MS. TANGHETTI: First off, we didn't run the simulation  
8 for 2008, so I don't have any comparable data for that.

9 But again, what we assumed was that there were far  
10 fewer renewables added to the system and also, by 2012,  
11 there wasn't that amount of energy efficiency as well, so  
12 our numbers differed there.

13 But then also another area that where we're seeing  
14 demand grow in the natural gas sector is we assume combined  
15 heat and power is all going to be fueled by natural gas. So  
16 again, that's one of the driving results for that as well,  
17 again as not the amount of renewables added to the system  
18 that they assumed in their study.

19 Also, if the number was 308 that you put in for sales,  
20 it's really an electric model, it should really be the net  
21 energy for load, which includes a significant portion for  
22 transmission losses, so you have to generate for those as  
23 well, so that could impact it as well, too.

24 MR. BRAND: Well, actually, we had that energy below  
25 the 353. I apologize, you probably couldn't read it on the

1 poor resolution of the table.

2 MS. TANGHETTI: Okay, good.

3 MR. BRAND: But the combined heat and power assumption,  
4 if there was more combined heat and power, which are not  
5 part of electricity sales, then our renewable number of 103  
6 terawatt hours would be able to be lower, then we would have  
7 higher gas-fired generation.

8 MS. TANGHETTI: As well as energy efficiency?

9 MR. BRAND: Yeah, right.

10 MS. TANGHETTI: So those assumptions do drive some of  
11 the gas use.

12 Again, the gas use it not -- I don't think it's that  
13 different. Again, if you look to 2012 and we start  
14 comparing the numbers, I don't think we're going to see as  
15 significant of a difference. But again, our numbers are  
16 going to be higher mainly because we didn't add as many  
17 renewables and that we did include combined heat and power,  
18 natural gas-fired.

19 COMMISSIONER BYRON: Thank you, that's a good  
20 discussion. Any other questions?

21 Ms. ten Hope?

22 MS. TEN HOPE: I just had one question. On your slide  
23 13, you say that the results would differ based on  
24 geographic diversity and renewables. Did you assume that  
25 the renewables were built out evenly across the State or --

1           MR. BRAND: No, solar we had all in the southern part  
2 of the State. And wind, I think we had more of it spread  
3 out. But it was kind of more looking at where the sites  
4 were.

5           MS. TEN HOPE: Okay, that's the basis of my question,  
6 because we presume that most of it will be in Southern  
7 California.

8           MR. KINOSIAN: Yeah, actually one question just  
9 following up on one of the earlier questions.

10          The Energy Commission assumed 4,500 megawatts of new  
11 combined heat and power projects. Did you assume any  
12 additional heat and power projects in looking at the gas  
13 usage?

14          MR. BRAND: I think we have some, but it really won't  
15 matter on gas consumption whether -- there might be some  
16 minor locational issues.

17          But if it's gas-fired generation, where it's combined  
18 heat and power, I don't feel that the efficiency differences  
19 of heat rate would matter that much, you still have that  
20 same amount of -- what it would do is break down that amount  
21 of renewables necessary to meet the 33 percent standard.

22          MR. ALVARADO: Well, we are spilling into the targeted  
23 lunch hour, but I did want to give the panelists an  
24 opportunity to field any questions from the public, or  
25 anyone else that might be on our WebEx. So if there's



1 anyone --

2 MS. KOROSEC: We do have one question on the WebEx, for  
3 the PUC staff, from Arthur O'Donnell, from Center for  
4 Resource Solutions. Arthur, you're line's open.

5 MR. O'DONNELL: Hi, can you hear me?

6 MS. KOROSEC: Yes, we can.

7 MR. O'DONNELL: I wanted to ask Nancy Ryan, but she's  
8 gone, so if the others could answer, please. In the absence  
9 of any analysis, if we used tradable renewable energy  
10 certificates to meet the 33 percent, that seems to  
11 presuppose an extreme policy decision that's not yet been  
12 made and it could lead to higher costs in what transmission  
13 constraints in this analysis.

14 Also, it seems that this report puts all reliability  
15 resources in the State rather than using western  
16 interconnected markets to supply them.

17 Why were those options neglected and what might you  
18 think the changes would be if they were included?

19 MS. MARKS: Hi, this is Jaclyn Marks and I'll answer  
20 your questions.

21 We did not model WECC because our cases were based on  
22 existing policy and right now WECCs are not allowed to be  
23 traded.

24 And as you know, the PUC put out a proposed decision on  
25 this. But it is a hot issue in the Legislature and the

1 Legislature is considering this issue for the 33 percent RPS  
2 legislation.

3 So as a result, you know, we don't know what the  
4 outcome will be and we'll wait to make a decision on how to  
5 model that once there's more clarity.

6 MR. O'DONNELL: Okay, but Nancy's position was that you  
7 really weren't going to be doing further analysis and the  
8 compromise with the Legislature right now is to allow for 20  
9 percent, so you might miss the boat.

10 MS. MARKS: We are not going to do more analysis for  
11 this study, but that doesn't mean we won't do more analysis  
12 in the future because I think WECCs could lower the cost, as  
13 you said, of the total program.

14 But as for the transmission, you know, renewable energy  
15 in other states could have transmission constraints, so  
16 that's another thing we need to consider.

17 As for your other question, our renewable integration  
18 analysis was very high level and it was based on the  
19 CPCU/Energy Commission joint decision on climate -- AB 32 and  
20 the greenhouse gas analysis.

21 And I'm not sure exactly if there were location  
22 assumptions or not. I know there were very high level cost  
23 assumptions.

24 And we're going to rely on the California ISO for more  
25 detailed analysis on this. So I think Dave Hawkins is the

1 best person to ask for more clarity.

2 MR. O'DONNELL: Thank you so much.

3 MS. KOROSSEC: And we have no other questions on WebEx.

4 MR. ELLIS: This is Jack Ellis, I've got one question  
5 for David Hawkins.

6 In the study you're about to do, you looked at or  
7 considered examining the impact of pushing the existing  
8 fleet and generate -- thermal generation to be built harder  
9 than is advertised. I've been told that some of the  
10 existing generators say that they could do more, that they  
11 could move faster if the compensation scheme were right.

12 MR. HAWKINS: Yeah. Excuse me. Yes, that's correct,  
13 we've had discussions with generation owners as to what it  
14 would take to do higher ramp rates and move the units  
15 harder. And those have been insightful.

16 And again, the issue comes down to a compensation  
17 issue. If we're going to move and stress the generators  
18 more, what is that compensation for being more aggressive  
19 and how do they cover their additional maintenance costs, so  
20 those are sort of ongoing discussions.

21 MR. ELLIS: Okay, and then a question for Ms.  
22 Tanghetti. Did you, in your study did you look at all at  
23 the impact of alternatives to gas-fired generation for load  
24 following and ramping?

25 MS. TANGHETTI: No, we just put that in as a proxy.

1 We're not trying to determine what's going to be there in  
2 2020, we just had some kind of a proxy.

3 We did choose between a simple cycle or a combined  
4 cycle, trying to determine whether it was more of a capacity  
5 need or energy need in the future.

6 MR. ELLIS: Okay, so at this point you don't know  
7 whether alternatives to gas-fired generation, period, might  
8 have some impact on GHG emissions and natural gas use?

9 MS. TANGHETTI: No, it's just a proxy that needs to be  
10 there.

11 MR. ELLIS: Okay, thank you.

12 MR. MAGALETTI: Mike Magaletti, with the Energy  
13 Commission.

14 Angela, I was interested in the difference in the  
15 natural gas consumption between your study and our study on  
16 not looking at the electrical system, but looking at the  
17 natural gas system.

18 And the one thing that you two were saying earlier  
19 about the CHP got me to thinking, you had almost 8,000  
20 megawatts of CHP at what capacity factor?

21 MS. TANGHETTI: I'm not sure exactly what capacity  
22 factor, and it wasn't 8,000 megawatts, it was about 4,500  
23 megawatts, still not insignificant.

24 But again, it's whether you include that on the power  
25 gen side or whether you include it in the industrial side,

1    so I don't think we're exactly -

2           MR. MAGALETTI:   That was the next question I had, how  
3    did you assign the gas -- the fuel for that CHP; did it go  
4    to the power gen side or did it go to the industrial side?

5           MS. TANGHETTI:   We modeled it at a reduced heat rate,  
6    so that part of the gas use was going for the process and  
7    part of it was going for the portion that was providing  
8    power to the grid.   So we tried to take that into account  
9    and only count the amount of gas use that was providing  
10   power to the grid.

11           So again, it could show up on either side of the  
12   equation.

13           MR. MAGALETTI:   But did the total -- and apologize for  
14   not being as familiar with your study.   Did the total gas  
15   use for both the electricity generation in CHP and the  
16   thermal, did that get factored into your assumption  
17   regarding increase in gas demand over time?

18           MS. TANGHETTI:   Yes.

19           MR. MAGALETTI:   Okay.   So I think when you say, Geoff,  
20   that CHP doesn't matter, I think it matters in total gas  
21   demand.

22           MR. BRAND:   Yes.

23           MR. MAGALETTI:   But you're actually right, in  
24   electrical generation there's less of a -- you'd have to run  
25   it, it's a more granule analysis, I suspect.

1           MR. BRAND: I think the big thing was the fact that the  
2 amount of necessary renewable generation to meet the 33  
3 percent standard is so much lower because electricity sales  
4 are lower because it's not counted, that's where the big  
5 change is.

6           MR. MAGALETTI: And that --

7           MR. BRAND: Actually, when I say it didn't matter, I  
8 mean to say from, one, you know, the amount of electricity  
9 generated to meet whatever demand in the future is for CHP  
10 or a normal generator, you know, the heat rates are not  
11 going to be terribly different, it wouldn't matter too much  
12 in the total amount of generation.

13          MR. MAGALETTI: But you'd have less renewable  
14 generation to back off your natural gas?

15          MR. BRAND: Yes, the natural gas, where the big change  
16 in gas consumption comes from was the portfolio mix of  
17 generation assets.

18          MR. MAGALETTI: Okay, thank you.

19          MR. ALVAREZ: Antonio Alvarez, from PG&E, just have a  
20 couple of questions on the ICF study.

21           I think you mentioned your own account for the intra-  
22 day uncertainty, with respect to wind or solar generation;  
23 right?

24          MR. BRAND: Yes.

25          MR. ALVAREZ: And also, the 24 percent, is that 24

1 percent decrease assigned to the peak day as a function of  
2 whatever winter wind or solar generation is expected?

3 MR. BRAND: What we did is essentially took our  
4 estimate for wind generation for 31 days, and took every  
5 day, and not -- reduced it by 25 percent, or 24 percent.

6 And actually, we did look at it seasonally, so January  
7 was actually 25 percent versus an annual average of 24  
8 percent. So that -- so therefore, we assumed the peak day  
9 occurred on the lowest wind generation day, so it was kind  
10 of the worst case scenario.

11 MR. ALVAREZ: Okay. One other question that I had, and  
12 perhaps a suggestion to look at the summer, given the summer  
13 injection season, and the additional storage that you're  
14 including. Summer for us, I think given the electric peak  
15 occurring in the summer will be probably a more stressful  
16 time, as well as the fact that we have -- perhaps in the  
17 spring we have most of the wind generation and, you know,  
18 summer solar generation.

19 And so looking at the variation, particularly with the  
20 day-ahead forecasts in both of those resources, coupled with  
21 the additional injections for the summer, when people are  
22 starting to load up for the winter, might be a good thing to  
23 look into.

24 MR. BRAND: An additional study, yes.

25 MR. ALVAREZ: Right. And I do have a couple of

1 questions on the Energy Commission study.

2 Again, my assumption in reading the study is that day-  
3 ahead uncertainty, hour-ahead uncertainty were not included  
4 in the simulations?

5 MS. TANGHETTI: The model does an adequate job of doing  
6 the day-head, but the hourly, intra-hourly that another  
7 simulation model captures is not.

8 But the day-ahead, it does a fairly good accounting of  
9 that.

10 MR. ALVAREZ: So it accounts for the uncertainty in the  
11 load forecast in --

12 MS. TANGHETTI: No, it's a determinate, we didn't run  
13 it in --

14 MR. ALVAREZ: Oh, so it's deterministic, okay.

15 MS. TANGHETTI: Yes.

16 MR. ALVAREZ: And what assumption was made about the  
17 combined heat and power, was it assumed -- I get the  
18 impression that there were some losses added to the savings.  
19 Is the assumption that all the combined heat and power is  
20 added at the customer side of the meter?

21 MS. TANGHETTI: I'm not sure exactly what side of the  
22 meter it's included, but we did include transmission losses.  
23 The scoping plan goals was about 30,000 gigawatt hours that  
24 they wanted in savings, and then we simulated about 32,000  
25 so we tried to capture the losses associated with that.



1 MR. ALVAREZ: So that implies that it would be small  
2 combined heat and power gain added, as opposed to a large,  
3 export combined heat and power?

4 MS. TANGHETTI: We didn't really make any specific  
5 assumptions about small. The way our model works is we can  
6 just plot different amounts in different regions in  
7 California, and so we just assumed that in total they were  
8 about 4,500 megawatts. Exactly what they were is not real  
9 clear.

10 MR. ALVAREZ: Okay, thank you.

11 And I have one last question for the Public Utilities  
12 Commission. There is a slide, and I'm sorry to get into the  
13 weeds, but when we look at the gas price sensitivity, we do  
14 see a reduction in the downside in terms of, you know, when  
15 gas prices are lower, the savings associated with a lower  
16 gas price scenario is not there, which is expected. But  
17 also, when the gas price goes up, somehow the total cost  
18 also increases, which is surprising to me. I would expect  
19 that the RPS generation would provide some page value. And  
20 I'm not seeing -- this is slide 16.

21 MS. MARKS: Antonio, we agree with you and we were  
22 surprised, too. And that was one of the findings of this  
23 analysis is that the 33 percent RPS provides a hedge, you  
24 know, as you can see from that slide, it decreases the range  
25 of volatility.

1 But in terms of the high end of the prices, you know,  
2 it doesn't decrease prices that much. So it was a  
3 surprising finding and something that could require more  
4 analysis and something to look into further.

5 MR. ALVARADO: Any other questions?

6 COMMISSIONER BYRON: Thank you, Mr. Alvarado. Thank  
7 you, Panelists, very much.

8 I think it's time for a lunch break. Let's reconvene,  
9 by the clock in the back of the room, at 1:40.

10 (Whereupon, the luncheon recess was taken  
11 at 12:40 p.m.)

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AFTERNOON SESSION

MS. KOROSSEC: I think we are missing one panelist, and we're trying to track her down, Ms. Malinowski-Ball. And we do have a substitution for CEERT, Danielle Mills will be participating in this panel.

I've just been told we do have a substitution for Julee, it's Jeffrey Hahn. Sorry about that, didn't realize it.

So I will turn this over to Ms. Doughman to moderate the panel.

MS. DOUGHMAN: Okay, thank you. What I'd like to do is have each of the panelists introduce yourself, and then I'd like to have you go through your thoughts in five to ten minutes, your thoughts on questions 9 through 12, and then we'll have some back and forth and then open it up for questions.

So Danielle.

MS. MILLS: Sure. Good afternoon. I'm Danielle Osborne Mills, with the Center for Energy Efficiency and Renewable Technologies. I'm standing in for John White today, who's testifying on an important piece of RPS

1 legislation.

2 I guess my overarching thoughts, sort of in response to  
3 all the questions, is that from the number of the  
4 conversations that I heard in the course of the morning,  
5 there seems to be a need for some general, low-carbon grid  
6 planning. And this would be a planning effort that would  
7 encompass all the various stakeholders, the various  
8 regulatory agencies, the ISO, the utilities, and focus sort  
9 of what we have now for low-carbon grid technologies,  
10 different renewable technologies, as well as demand response  
11 storage, as well as other complementary infrastructure  
12 technologies.

13 Look at what we have now and look at how all that fits  
14 together and just try to think about ways to look at the  
15 system more holistically and sort of incorporate all the  
16 different climate and the energy goals that we have all at  
17 once, and I think this will help with some of the long-term  
18 planning concerns that we have.

19 In response to the first question, just on electricity  
20 integration and integrating variable amounts of renewable  
21 energy, I want to call everyone's attention to a study that  
22 came out by the North American Electricity Reliability  
23 Corporation this spring, earlier this spring.

24 This report had a number of important findings that  
25 could be useful to both the CEC, the ISO, and the PUC in

1 terms of integrating variable renewable resources.

2 Specifically, I'll go through a couple of those  
3 findings. First, it noted that wind plants are already an  
4 important contributor to grid reliability. And their  
5 performance capabilities now equal or exceed that of  
6 traditional power plants.

7 They also found that the policies that govern how  
8 transmission lines are planned, paid for, and permitted need  
9 to be updated so that transmission can be built to connect  
10 to new wind projects. And that's a thing that definitely  
11 we're all familiar with.

12 Also they found that while wind power can be  
13 characterized by variability and uncertainty, grid operators  
14 already constantly accommodate variability and uncertainty  
15 while dealing with changes in electricity demand and  
16 unexpected outages of traditional power plants.

17 They also found that the reliability standards must be  
18 fair, transparent, and performance based.

19 So these findings led them to a number of suggested  
20 reforms, including the consolidation and cooperation of the  
21 small, balkanized grid operating regions to form larger  
22 operating areas. And that may offer significant reliability  
23 and economic benefits.

24 It also found that the wind forecasting should be  
25 expanded and wind forecasting should be integrated into

1 power system operations.

2 Power plant scheduling and dispatch should be conducted  
3 for shorter intervals than is commonly done today, somewhere  
4 like five or ten minutes, rather than hourly, and this will  
5 greatly enhance grid flexibility.

6 Also, the flexibility of the grid can be enhanced by  
7 adding new types of generation and demand response  
8 resources, and by creating markets to incentivize this  
9 flexibility.

10 In terms of some of the policies in the scoping plan, I  
11 think that certainly the goals outlined in the scoping plan  
12 will help California reach its greenhouse gas goals. And we  
13 heard that pretty clearly from the CEC's presentation this  
14 morning, when she discussed the interplay between energy  
15 efficiency and -- energy efficiency achievement and  
16 renewable energy procurement.

17 The CEC study highlights the need to analyze and plan  
18 for the interactions among the State's various policy goals.

19 I think this also highlights the need for better  
20 portfolio-based planning, as I mentioned earlier, on behalf  
21 of the load-serving entities to ensure that they're meeting  
22 their greenhouse gas targets and complying with other  
23 regulations more effectively.

24 Additionally, I just want to highlight that the scoping  
25 plan does mention a few supporting policies in the 33

1 percent RPS section, including transmission planning, as  
2 well as expansion of California's current feed-in tariff  
3 program. And I think feed-in tariffs are especially --  
4 could be especially beneficial for the geothermal  
5 technologies, biomass technologies, and fuel cells with  
6 manure.

7 And so that sort of gets to the third question that you  
8 asked all of us. Feed-in tariffs can provide a great deal  
9 of certainty for these markets and I think all of these  
10 markets provide value to the ratepayers and this feed-in  
11 tariff would help address that value that they provide.

12 I think I will leave it at that for now.

13 MS. DOUGHMAN: Steven.

14 MR. KELLY: Thank you. I'm Steven Kelly, with the  
15 Independent Energy Producers Association.

16 And one, I want to thank the Commission for having this  
17 workshop, and not only this Commission, but the Public  
18 Utilities Commission in doing the analyses that are kind of  
19 addressing the integration of 33 percent RPS.

20 Because I think it's important that the State agencies  
21 begin the process of sending the proper signal to the  
22 public.

23 I mean, I'm amazed repeatedly that in the wake of AB  
24 32, which is essentially transforming or attempting to  
25 transform our economy, people are asking the question, well,

1 is this going to cost something? And I guess my answer has  
2 always been, yes, it probably will. You're going to change  
3 your economy from a primarily fossil-based economy to a  
4 primarily non-fossil-based economy, yeah, that may well  
5 incur some costs.

6 But what I'm happy to see in the studies that I've seen  
7 so far is that the costs really are not that significant  
8 given the uncertainties of the evaluation and the range of  
9 the things we're trying to do.

10 The PUC study, I think, indicates that there's a ten  
11 percent cost increase, potentially, for going to 33 RPS,  
12 it's a 2.8 percent incremental cost increase for going to  
13 the 20 percent.

14 Those are well within a range of, in my mind,  
15 reasonable, given the task that's in front of the State in  
16 trying to move to this new structure that we are trying to  
17 do.

18 So I think that's important and I think it's important  
19 that the agencies couch this in the proper language because  
20 it's often couched improperly, I think.

21 For example, we've read over the last couple of years a  
22 lot of studies about renewables, and the renewables need gas  
23 backup, natural gas-fired backup, and that's an incremental  
24 cost to the system.

25 I actually think of it as the renewables backing off



1 the natural gas that we need, anyway.

2 I mean, in this State there's only two types of  
3 technologies, probably, that we're going to bring to bear,  
4 natural gas to surf load and renewables, there's not a lot  
5 of choices. So we've got to plan for both.

6 We've got to plan for natural gas to serve load. And  
7 when the wind blows at two o'clock in the morning, or  
8 whenever it is, it's backing off natural gas. That's  
9 probably a good thing at that point.

10 And, hopefully, we can build the infrastructure to  
11 create the potential for the electrification of the  
12 transportation sector. But we've got to start that sooner,  
13 rather than later, because if we wait it will never happen.  
14 Things will change, we won't have the infrastructure when  
15 the transportation sector's ready to kick into this.

16 So I'm here to encourage the Commission to continue  
17 focusing on this and looking at this as a positive. These  
18 costs are well within the range, in my view, of achieving  
19 the goals and the tasks. The public is probably well  
20 positioned to take these on as an increase in their monthly  
21 bill.

22 And all the public policy surveys that I've read to  
23 date, particularly in California, seem to suggest the public  
24 supports this.

25 Now, I want to reemphasize this issue that the focus

1 shouldn't be the cost of the RPS per se, it's really the  
2 cost of AB 32.

3 And what is it -- what's going to be the cost of doing  
4 nothing? And we know we can't model that. I mean, it's  
5 possible we can model the RPS costs, so everybody does that.

6 The thing that's missing is what are we going to do if  
7 we don't do this? And that's impossible to model very  
8 accurately, in my view. And so it's an unknown, so nobody  
9 focuses on it.

10 But if the renewables, for example, can be used to  
11 electrify the transportation sector, can be used as a  
12 storage, so to speak, through that mechanism, that's a good  
13 thing and it's a positive thing and I doubt if we can really  
14 value that very well at this point in time.

15 So we are looking to make investments today to get the  
16 infrastructure in place to make policy implementation  
17 changes in maybe eight to ten years.

18 I just want to point out in that regard, I was at the  
19 Western Governor's Association meeting a week and a half  
20 ago, I guess, in Salt Lake City, and the Secretary of Energy  
21 was there, and I think it was him who made the observation  
22 that -- in this point about what are we comparing it to?

23 And there were people that were questioning climate  
24 change. But his observation was that what we're doing is  
25 buying insurance.

1           And he made the observation, with his Nobel laureate  
2 intelligence behind him, so I take it all without  
3 investigating, that the difference between the glacial  
4 period in North America, when everything was covered with  
5 ice, and today is like four degrees.

6           I read some stuff that suggests we've changed -- the  
7 temperature's gone up a degree or so, a degree and a half in  
8 the last 50, 60 years.

9           But the point is that the change, it doesn't take a lot  
10 to really, dramatically change the environment.

11          And what we're doing in pushing an expanded RPS,  
12 combined heat and power energy efficiency and clean natural  
13 gas is buying insurance to prevent that change, and we can't  
14 calculate what that impact of that change is going to be,  
15 and so we're just going to have to do it on gut feeling.

16          And that's kind of what the Legislature, I think, did  
17 as well.

18          I will note, though, a couple of observations in light  
19 of the reports. There's a lot of focus on one or more of  
20 the renewable technologies and, you know, we're going to  
21 meet 33 RPS with all wind, all intermittents. My God, we  
22 can't handle this on the system.

23          It's only going to be a portfolio approach of all the  
24 renewable technologies, supported by natural gas, that's  
25 going to get us there successfully.

1       We know we need natural gas for load following,  
2   reliability, and all those reasons. Some of the renewables  
3   can provide some of those, biomass, geothermal, which aren't  
4   talked about very much, provide baseload amounts of energy  
5   that can be used, and very successfully.

6       We've got the solar, which is kind of a peaking  
7   resource.

8       And then there's the low-cost wind that kind of melds  
9   with the peak and then, hopefully in the future, will be  
10   serving to store energy in the transportation sector,  
11   electrifying vehicles.

12       So those all come together, they all have an individual  
13   role to play in transforming this economy.

14       But we need a portfolio, in my view. And analytics  
15   that focus on a scenario that is all intermittent is wrong  
16   on its face, in my view.

17       And if that's occurring, that means that the  
18   methodologies we are using to secure resources is misplaced,  
19   least cost/best fit isn't applying, probably, if all we're  
20   getting is intermittent resources that are going to require  
21   a lot of backup and support.

22       And that's probably where we need to look, to make sure  
23   that we are using the valuation tools, the procurement tools  
24   to minimize the costs of meeting these goals, and I have a  
25   feeling that that's going to take a portfolio across all

1 technologies in the end of the day.

2 I guess the other thing I would just add, there was a  
3 discussion this morning about the over-gen situation that  
4 occurs and the reliability problems with that.

5 And again, when I hear that language about over-gen, I  
6 mean, over-gen has occurred in California since we had  
7 hydro, and we imported from the northwest. It's not a  
8 phenomenon of the RPS.

9 But as a matter of fact, if you end up in a scenario  
10 where you are backing down natural gas, in a low carbon  
11 environment in the future, you know, that's probably a good  
12 thing. You need the natural gas to be there, it provides  
13 amounts of incredible reliability for services. But if you  
14 can back it off in an over-gen situation, that's probably a  
15 good thing.

16 It would be very good if we could store that energy.  
17 And I'll note that in the legislation that's being discussed  
18 across the street, there's an attempt to get rid of storage  
19 of renewables in the State, as a means I think to minimize  
20 the amount of RECS. It makes no sense to us.

21 But that's something we've got to look at to make sure  
22 that we have a program in place that allows the renewables  
23 to be used for storage.

24 And the context -- I see Bob's saying where's that  
25 coming from -- it's the simultaneous delivery language in

1 the legislation, everything's got to be delivered right  
2 away. That kills storage under the way the language is  
3 drafted now.

4 So we've made that comment in a letter we sent to the  
5 authors of the SB 14.

6 But simultaneous delivery and storage are incompatible  
7 in the way that it's currently drafted, and that's a problem  
8 and it doesn't serve a public policy purpose. So that's one  
9 observation.

10 The other thing I'll just say, kind of things to note  
11 of concern, the -- there's a lot of emphasis in the analysis  
12 about the 33 percent RPS, the huge increase in CHP, and the  
13 very, very large increase in energy efficiency.

14 Now, let me make a couple of observations and this may  
15 get to some of the modeling techniques.

16 But related to CHP, we are facing a situation where the  
17 PURPA must-buy obligation is probably going to be suspended  
18 this year, which means that that vehicle for bringing on new  
19 HC will probably not be available to people, and we may be  
20 moving to some sort of contractual mode. It's not clear  
21 whether feed-in tariff of CHP is implementable. People are  
22 talking about that.

23 I think anybody in the CHP business, myself, and some  
24 of the other trades that are in discussions with the  
25 utilities today, do not believe that those numbers are

1    achievable, the 5,000 megawatt increase, under the programs  
2    that are being discussed today. So I'll just make that  
3    observation.

4            Energy efficiency. I've been around a long time, most  
5    of the energy efficiency has come through -- in California,  
6    I think, has probably come through this Commission  
7    implementing appliance standards and housing standards.

8            It's ironic that we're talking cap and trade, but we're  
9    in a situation where all the money from cap and trade is  
10   designed to flow back to the consumers to mitigate the rate  
11   increases, so they don't change their behavior.

12           So I'm assuming that there's not going to be all the  
13   energy efficiency that everybody's talking about, unless you  
14   can get it through building standards.

15           RPS, you know the track record there. Whether we're  
16   going to achieve 33 percent by 2024, or 2030, you're guess  
17   is as good as mine. The track record isn't so good.

18           So putting all that together, when we look at the costs  
19   of all of this stuff, and everybody's concerned about the  
20   implementations from a grid reliability perspective of  
21   having this stuff configured into the grid, I don't see it  
22   happening as fast as people would like, or I would like, so  
23   I take the concerns -- they're important concerns, from a  
24   grid reliability perspective, but I am not thinking it's  
25   going to be a concern that's going to arise on my watch by

1 2020.

2 I mean, I remember these debates being discussed ten  
3 years ago. And what did we bring on, 800 megawatts in the  
4 last seven years? I mean, you know, the grid can handle  
5 that.

6 So I guess to close would be to say that these studies  
7 are very important. I think we need to present them in a  
8 public in a way that doesn't undermine the success of  
9 achieving these goals.

10 And on the analytics for the technical work, there's  
11 people that are going to be working that and trying to get  
12 that smoothed out, and have a sense of what it's going to  
13 cost.

14 But meanwhile that's going to take many years. I think  
15 we do need to get moving on installing the new natural gas  
16 that we need to meet load demand, support the renewables,  
17 and so forth, and then bring the renewables on as quickly as  
18 possible.

19 Those are my comments, thank you.

20 MS. DOUGHMAN: Thank you.

21 Carl.

22 MR. ZICHELLA: Good afternoon. I'd like to thank you  
23 all for inviting me to be here. I'm Carl Zichella, I'm the  
24 Director of Western Renewable Programs for the Sierra Club.  
25 I've been working on a renewable energy transmission



1 initiative, the Western Governors Association RES process.

2 I've been working with other colleagues to work with the  
3 Department of the Energy and the Department of Interior on  
4 their renewable energy program for California and the west.

5 And I really appreciate, as my colleague said, this is  
6 a really important workshop, these are really important  
7 reports.

8 And I wanted to highlight a few of the things that I  
9 think we need to be looking at a little more carefully when  
10 we start talking about balancing resources and the pressures  
11 on the grid.

12 I'm not going to comment on modeling, I'm not a  
13 modeler, but I will mention a few things.

14 I think Steve said some of the things that I would like  
15 to have said and others I think I take a slightly different  
16 emphasis on.

17 I think we need to look at the possibility of how to  
18 balance renewables with other renewables in California. I  
19 think we have some timing issues that make us able to do  
20 some of that.

21 Of course, we have intermittent resources, but  
22 sometimes they will cycle on at different times.

23 Not only that, but I was pleased to see some of the  
24 studies look at the entire western interconnection, and  
25 reminding us that we're part of the entire western

1 interconnection and there are balancing opportunities on the  
2 western grid beyond that.

3 In some of the RES work that we've done, we've noticed  
4 that Colorado wind can help balance Wyoming wind, for  
5 example. And I don't think we know enough about how  
6 external resources we're importing may be able to help us  
7 balance our renewable load.

8 I think there are issues with congestion on the lines  
9 that we don't have enough information about, that we're  
10 making some assumptions about congestion increasing costs,  
11 and increasing the difficulty of integrating renewables  
12 when, in fact we know that there are many long-term  
13 contracts that have been signed since 2001, that will be  
14 coming to a term on the next five, ten years, sometimes  
15 sooner.

16 These contracts may not necessarily be renewed. Some  
17 of them are for out-of-state resources that we may not need  
18 if we're bringing renewables on. If we're going to be, as  
19 LADWP is doing, trying to replace some of their coal load  
20 with renewables, that could actually free up a fair amount  
21 of capacity on that system.

22 One of the things I think we also need to look at is  
23 integrating our system more completely. I mentioned that  
24 earlier today, not having such separation between IOUs and  
25 the publicly owned utilities, so that we can actually take

1 better advantage of the totality of our system and deal with  
2 some of these congestion issues and these integration issues  
3 a little more effectively.

4 On related policies that are affected by this, I think  
5 the distributed generation information we got today, from  
6 the Public Utilities Commission, was very interesting.

7 It does show a price parity coming into play under some  
8 scenarios. I think that that's really encouraging. But I  
9 think we have to look beyond just price as a driver for  
10 distributed renewables.

11 And by the way, it isn't always rooftop solar. Some of  
12 these very large commercial facilities, and also some  
13 ground-managed facilities of modest, more modest scale on  
14 disturbed private lands, as some businesses are beginning to  
15 look at.

16 There's the Edison Mission Company, that is a business  
17 plan looking at smaller scale, but still pretty big, I mean  
18 100 megawatts or so, closer to load on disturbed private  
19 lands. They have a much easier integration play for us.  
20 And I don't think we've really looked at that intermediate  
21 model very much. It's all been pretty much rooftop and  
22 urban areas, and I do think this is a part of that bigger  
23 picture.

24 I think if we really want to see distributed generation  
25 accelerate in this State, we're going to have to look at

1 some new policies.

2 Feed-in tariffs have been under investigation by the  
3 Public Utilities Commission, as well as the Energy  
4 Commission, and I think we need to look at incentives for  
5 scale.

6 Right now our policies are disincentive for individual  
7 homeowners or business owners to scale their programs, their  
8 systems for their buildings larger than their own needs, and  
9 I think that's a mistake.

10 If we're looking at trying to get a bigger increment to  
11 reduce the amount of transmission that we have to construct  
12 in this State, we ought to be providing incentives for  
13 scale, and that means pricing incentives up front so that  
14 people can get financing, so that they can actually have an  
15 investment that has a return on investment for selling their  
16 excess power back into the grid.

17 And we'll begin to see scaling of systems that actually  
18 will make a lot more sense, I think, for us.

19 This is a model that's worked in Germany. It's worked  
20 maybe too well in Spain, where they've had to roll their  
21 program back.

22 But I think if anything it demonstrates that having a  
23 system that provides incentives to build to a scale larger  
24 than your own needs is very effective.

25 Uncertainties, I think we heard a lot about gas usage,

1 and pricing forecasts, and how all over the map they are,  
2 and we do need to reconcile those.

3 I think some of those scenarios make it look like  
4 renewables don't make any sense, and that's more than just  
5 counter intuitive, I surmise that something's wrong there.

6 I do think that needs to be straightened out.

7 Also, we saw some uncertainties today described between  
8 the net short between various entities. We need to sort of  
9 get more of consistent methodologies in the State so we have  
10 a better view of what it is we need to do in order to meet  
11 these goals.

12 I think I heard a lot today, and I think Steve did  
13 touch upon this briefly, is we're looking at the cost  
14 question too narrowly. We're comparing the costs in the  
15 future against the base case or against today's pricing.  
16 And while that's useful for getting a snapshot of the  
17 commodity price, it's not useful from a cost benefit  
18 perspective.

19 I think it's in fact the wrong question, the analysis  
20 is way too narrow.

21 The benefits of getting renewable power in have to be  
22 balanced against the cost of not doing anything, and the  
23 impacts that have been fairly well, I think, established in  
24 California, in the PIER program. There's been a lot of good  
25 research that's been done about the potential impacts of

1 climate change.

2 I think it's very interesting timing that just  
3 yesterday the Secretary of the Interior was in Fresno to  
4 talk about a water shortage that has become retractable in  
5 this State, where farmers are having to idle large amounts  
6 of land, and our ability to bring species that are part of  
7 an ecosystem of great commercial value to California back is  
8 being compromised by an increasing drought. Which under  
9 every scenario forecast in California is going to get worse  
10 under climate change?

11 And one of the forecasts this State has made is an 80  
12 percent reduction in snow pack by the end of the century,  
13 under business as usual scenarios.

14 And I have to say that the cost of that is just simply  
15 off the charts.

16 If we're just talking about electricity costs that are  
17 seven percent in 2020 than they are today, and that's the  
18 conversation we're having, I think we're really making a big  
19 mistake, and we're hampering the public's ability to  
20 understand why it is we need to do this in the first place.

21 The Secretary of the Interior also, today, announced a  
22 plan for the Mojave, to help identify areas for solar energy  
23 development on public lands that could -- that be expedited  
24 in terms of bringing them online. And also identifying  
25 these projects in places that are more easily permitted.

1           And what he means by that is fewer environmental  
2 conflicts.

3           A lot of those are going to overlap with zones that  
4 we've identified in a renewable energy transmission  
5 initiative, which has had a similar mission.

6           And I think that's an uncertainty that actually could  
7 help address some of the timing issues, perhaps, that we're  
8 looking at and our ability to meet this 33 percent goals.

9           There are issues that are not easily quantified in a  
10 model, that I think are going to have a profound impact on  
11 whether or not we're going to hit these goals.

12           Some of that is inter-agency cooperation at the Federal  
13 level, and inter-agency cooperation between the Federal and  
14 State governments.

15           And I think that this new administration, and the  
16 interest of the State to solve that problem can really help  
17 us. I don't know how you factor that into an analysis, like  
18 the IEPR, but I'll just point out that that's part of the  
19 context that we're operating in.

20           Talking about the cost benefit analysis for just  
21 another moment, it's been forecast by climate scientists  
22 that a one degree increase in temperature will lead to a 20  
23 percent extinction of desert species.

24           And California has the second highest level of endemism  
25 of wildlife species and plant species in the United States,

1 after Hawaii.

2 We have a great deal to lose if we don't solve this  
3 problem. We need to have this continue to be part of that  
4 conversation.

5 I think, in the pace of technological innovation, the  
6 storage question has come up several times. If we can get a  
7 better sense about which technologies we ought to be  
8 promoting in order to help solve this issue, I think some  
9 people talked about thermal storage for concentrating solar  
10 plants. It's feasible now, it's practical now.

11 We should, perhaps, be looking at ways to create  
12 incentives for those to be deployed earlier on, to help  
13 smooth out some of the intermittency problems that we've  
14 been talking about.

15 There are others that technology's actually moving  
16 fairly quickly. And I'm not an expert, or expert enough to  
17 sort of forecast when they'll be commercially viable, but I  
18 think that is something we need to look at in much more  
19 detail.

20 What's the outlook for capacitors, what's the sort of  
21 timeline on those?

22 What's compressed air look like? Do we have an  
23 opportunity to utilize that technology in California.

24 Molten salt, as I mentioned, we've already seen its end  
25 use in Spain already. There's no reason why it couldn't be



1 used here, in California, to extend the peak that solar  
2 thermal plants produce.

3 I mentioned earlier, it's sort of a pet peeve of mine,  
4 I'm going to say it again, combined systems and goals around  
5 the POUs and the IOUs, the publicly-owned utilities and the  
6 investor-owned utilities to help solve some of the  
7 congestion and pricing issues.

8 There's no reason in the world why ratepayers should  
9 have to pay line charges for two or three separate entities,  
10 when we should have a combined system in the State.

11 And we will have a much easier time siting the  
12 transmission we need in California if we're not having to  
13 have fights over duplicative lines in sensitive areas.

14 I think we're starting to come to a real consensus  
15 about how to approach transmission in the State. A lot of  
16 stakeholders have worked now for over two years in the RETI  
17 process on this, the Renewable Energy Transmission  
18 Initiative.

19 And I think that there's no reason to sort of pretend  
20 that this conversation shouldn't happen or isn't happening.  
21 We should be figuring out ways to make it happen as quickly  
22 as possible when it comes to combining the transmission  
23 assets for the use of both privately-owned and publicly-  
24 owned utilities.

25 I think I'll stop there.

1 MS. DOUGHMAN: Thank you.

2 Let's see, Jeff Hahn.

3 MR. HAHN: Good afternoon. My name is Jeffrey Hahn,  
4 I'm the Director of Environmental for Covanta Energy.

5 Covanta's one of the several companies in the  
6 California Biomass Energy Alliance. And Julie is on the  
7 other side of Sacramento on SB 14, and that's one of the  
8 topics that I'll be talking about, so she asked me to step  
9 in.

10 I assume, from your report and your background you know  
11 a lot about biomass, but let me just reiterate some facts.  
12 Your own data show, and this was published early this year,  
13 from January 1<sup>st</sup>, of 1998 to June 30<sup>th</sup>, of 2008 that biomass  
14 actually supplied over one-third of the megawatt hours of  
15 all the renewables in California.

16 And so I think that's important to know that for the  
17 biomass industry, we need no transmission, because the fuel  
18 comes to us. That is part of another problem I'll talk a  
19 little bit later about.

20 We are base-loaded 24/7, we run like a regular power  
21 plant.

22 And the other is the co-benefits that we have in the  
23 field that we use. And co-benefits is a big part of AB 32.

24 We avoid methane, which is 20 to 25 times more potent  
25 than global warming potential.

1       When waste is left in the forest, from forest trimming,  
2 ag, from incomplete ag burning, and land filling, even with  
3 the new early action measures, materials that we take out of  
4 the landfill and use as fuel.

5       So we have now 33 or so operating biomass plants in the  
6 State, over 650 megawatt capacity. And as I said, our fuels  
7 are from the forest, from ag waste, and from urban waste.

8       But part of the urban waste that we get is not in  
9 competition with the people who are trying to make biogas,  
10 because the waste that we burn doesn't have a lot of gas  
11 generating potential, as other biomass does, regular biomass  
12 from MSW.

13       So what are our issues. The first one, in particular,  
14 is getting enough electrical revenue for the power that we  
15 sell the IOUs and the POUs. That's the subject of SB 14.

16       I've got a list here from Julie of all the things that  
17 happened with the type of contracts we have, where we're  
18 getting less and less for the electricity we produce, and we  
19 have to buy the fuel, and we have to truck it to where we're  
20 going to burn it, and those costs are going up.

21       So the plants, there's also proceedings now, with the  
22 IOUs, to take back some of the money from the SRAC and go  
23 back into the years they've already paid us and try to  
24 recover some of that money. So that's the first one.

25       And again, then, some competition for biomass.

1       Our fuel prices tend to go up, certainly with diesel,  
2 and there's also becoming some competition for biomass.

3       On the flip side of that, if we do not survive well,  
4 the dreams of ending ag burning by 2010 won't happen,  
5 because we are the place that can handle the ag waste,  
6 certainly in San Joaquin Valley, and we're in talks with the  
7 District there to make sure they don't back off from the  
8 implementation of no ag burning in 2010.

9       One of the most important things, that I can't stress  
10 enough, is something that's happening with the  
11 implementation of the scoping plan, and also at WCI, and  
12 that is the concept of looking at carbon neutral for  
13 biomass.

14       And I want to give you an example, from our six  
15 facilities that are over 135 megawatts. The report from  
16 CARB is about two months late on how they're going to handle  
17 this. They put it in the scoping plan and adopted it at the  
18 last minute.

19       When we report, as we have to CCAR, at least Covina  
20 from 2005 emissions, and this year we've reported our 2008  
21 to CCAR, we separate the CO2 biomass from CO2E.

22       And to give you an example, for the 135 megawatts in  
23 six facilities we about 8,000 metric tons of CO2E, half of  
24 that's from start-up fuel, natural gas and propane, half of  
25 that's from reagents that we use to scrub out the acid gas,

1 and a little bit of that, very little, is from the N2O and  
2 methane from the combustion process, but we use real data.

3 On the contrary, we have a million 300,000 metric tons  
4 of CO2 biomass.

5 So think of this, if for some reason that CO2 biomass  
6 creeps into and becomes CO2E, six plants would have to pay  
7 anywhere from, I think it's \$10 a ton in the auction or --  
8 the auction of a cap and trade system for the allowances,  
9 that's \$13 million, up to 39 if it comes up higher over  
10 time.

11 Our plants can't afford them now, we can barely keep  
12 them operating on the electrical rates we're getting.

13 But if that happens, and that's both under the CARB, as  
14 well as cap and trade, as well as the Western Climate  
15 Initiative, and equal disturbing tendency is the language  
16 written into Waxman-Markey, on the definition of biomass.

17 It doesn't affect so much the ag waste and the urban  
18 waste, but it does the waste from the forests, and which  
19 forests and some of the definitions there will not be good  
20 for additional biomass.

21 And this carbon neutrality from the Air Resources Board  
22 gets into the point of what can truly be carbon neutral if  
23 you have to truck the material, using fossil fuels, to your  
24 facility to burn it?

25 So that that issue has to be solved or your whole

1 baseload and the Governor's Executive Order to have a  
2 certain percent of renewables as biomass won't be there.

3 And so your modeling and all the calculations, if  
4 something isn't done soon, you're going to have to start all  
5 over again because that other column that you saw this  
6 morning was all the biomass, and it could conceivably not be  
7 there if some things aren't fixed in terms of the price we  
8 get for electricity and keeping us, our biomass CO2 out of  
9 CO2E and having us fall into cap and trade.

10 The last couple of comments, question nine and ten we  
11 can fit into the -- it's not a concern for biomass, there's  
12 only a certain amount.

13 Number 11, you know, again, we're base loaded, we're  
14 not intermittent, so we can help alleviate that issue,  
15 irrespective of what the other speakers have said for other  
16 technologies.

17 And again, number 12, you know, we just need better  
18 funding, as Carl was talking about, real funding, to keep  
19 renewables that have the part of the renewable portfolio  
20 standard, as well as all the air pollution co-benefits in  
21 terms of reducing things in the value like PM2.5, so from  
22 open burning.

23 And so I'll end my comments now. But I'm not sure  
24 you've heard all that and how your models would be affected  
25 if the -- you know, the number of megawatt hours from

1 biomass disappears before 2012. Thank you.

2 MS. DOUGHMAN: Thank you.

3 Is Martha online, available?

4 MS. DAVIS: Can you hear me?

5 MS. DOUGHMAN: Can you speak up a little?

6 MS. DAVIS: Yeah, hold on a second, I've got you on --  
7 is that working better?

8 MS. DOUGHMAN: Yes, thank you.

9 MS. DAVIS: All right. Thank you very much for the  
10 invitation to participate in the discussion.

11 My name is Martha Davis, I'm the Executive Manager of  
12 Policy Development for the Inland Empire Utilities Agency.  
13 We're located in Southern California. We originate to  
14 distribute imported water supply within the Chino Basin and  
15 to provide 800,000 people. I sit on the Board of the  
16 Metropolitan Water District of Southern California.

17 We also provide regional sort of treatments to the  
18 southern cities located within our service area. And so we  
19 have basically three products, recycled water, compost,  
20 which is what we're using for the sewage sludge, and  
21 recycling it locally, and the producing renewable energy.

22 I also am currently the Chair of the Energy Committee  
23 for the Association of California Water Agencies, so I've  
24 been leading them in the last year on getting involved in  
25 renewable energy issues.

1       And my agency has got started really early, really on  
2 the energy crisis, on getting involved in renewable energy.  
3 And we're like the first public agency that gotten at the  
4 headquarters installed digester projects both for sewage  
5 sludge, and in partnership with the local dairy industry.  
6 So with the California Energy Commission's assistance, we  
7 looking at a regional digester down here in Southern  
8 California. And we've just installed 3.5 megawatts of solar  
9 energy.

10       And I think one of the things that I would bring to  
11 this discussion today is the need to really expand the  
12 context of the partnership among the different agencies that  
13 are trying to address both the Governor's objective for  
14 renewable energy and AB 32 implementation, and bring water  
15 and waste water agencies into a proactive discussion about  
16 what they could bring to the table.

17       Certainly, as the IEPR identified several years ago,  
18 the water/waste water industry is currently using about 20  
19 percent of the energy usage in the State. There is  
20 certainly, because of the large amount of internal  
21 combustion engines, one of the target factors for helping to  
22 achieve AB 32.

23       And as in the article that was described earlier, we  
24 are directly in the crosshairs of the impact of climate  
25 change. So for us, renewable energy is as much about



1 mitigation -- well, adaptation, as it is about mitigation,  
2 and will be a part of trying to address this bigger picture  
3 of impact of climate change on our long-term water supply.

4 If you flip around and look at it from the stand point  
5 of the partnership, we are one of the factors that are  
6 suggesting increased population, increased services, and  
7 significant increases in energy usage.

8 Energy is our most controllable cost center, so a  
9 higher cost center is typically labor, next to the energy,  
10 and then applying of the chemicals.

11 We have a great deal of interest in figuring out how to  
12 manage these energy problems.

13 But we also have a unique combination of capacity to  
14 develop renewable energy in having the wind, the engineers,  
15 professional staff, along with the load to be able to use  
16 particularly on-site distributed generation.

17 One of the key obstacles to doing that is, as we've  
18 identified by a number of participants is seeing the real  
19 value of the energy that is being produced. Our agency was  
20 a sponsor of the feed-in tariff, AB 1969, which currently  
21 has another bill just to help clarify the feed-in tariff, of  
22 SB 32.

23 We've also participated in legislation on net zeroing.  
24 All of those, within the last few years, are new policy  
25 directions aimed at one core issue, how to actually get the

1 value of the renewable energy that is being produced back to  
2 the entities being affected and the facilities that create  
3 the renewable energy.

4 I want to also clearly state, and it's been alluded to  
5 in today's conversation, it is worthy of in particular, are  
6 some of the cross-impacts of regulations that will end up  
7 impeding some of the renewables development.

8 I think the one that jumps out as an example for me is  
9 the regulation of 1110.2, which basically addresses how much  
10 biogas can be combined with natural gas in order to run an  
11 internal combustion engine.

12 And this is getting at that balancing act of  
13 environmental impact between not wanting certain types of  
14 emissions, but the result of it is to become an obstacle for  
15 the ability to use a renewable energy, like biogas is, that  
16 could be produced by, in particular, the waste water  
17 agencies.

18 I think that I would surely support some of the  
19 comments that have been made in this panel, the need for the  
20 holistic planning. I think that's one of the things that  
21 really jumped out of this morning's conversation, in  
22 particular looking at some of the models. I'm not an expert  
23 on the modeling, but it's clear that there needs to be at  
24 least some scenarios that deal with what's a real approach  
25 and with holistic planning scenarios, and integrating a

1 broader array of value to society of the investment which is  
2 being made.

3 I second the point that was made about the different  
4 scales of renewable energy investments. I think there's  
5 been a lot of focus on these really large plants. I think  
6 that we, in particular, are going to need renewables on many  
7 different scales. And I think the partnership with the  
8 water and the waste water industry, and the global  
9 government should think about is the ability to do a lot of  
10 smaller renewable generation, located or co-located with  
11 loads, or doing new load, and that's going to have, I think,  
12 a really exploding implication for some of the transmission  
13 issues that were discussed earlier this morning.

14 Another issue I just want to cull out, particularly on  
15 the pricing, is to go back to the notion of what is the  
16 value in these pricing studies.

17 One of the examples of where the State missed,  
18 unfortunately, on being able to get more renewable energy  
19 out of an incentive program was the California Solar  
20 Initiative, which was so focused on making sure that only  
21 one megawatt was -- or \$1 million was being put in per site,  
22 which was appropriate, trying to cap the amount of money  
23 that was going into a site. But inadvertently it also  
24 capped everything at one megawatt per site.

25 And I know from a number of water, waste water agencies

1 that participated in this program, that they would have been  
2 happy to install an additional one, two, three megawatts at  
3 each of the sites at their own expense.

4 Because what they saw in the incentive for the CSI  
5 program was intending to make development into installing  
6 the solar energy, but they clearly have -- for additional  
7 solar being installed, but they couldn't qualify if they  
8 went over one megawatt.

9 Very interesting example of well-intentioned plan that  
10 actually deterred the installation of more solar.

11 And just in closing, I think that one of the things we  
12 ought to ensure we want to do is get a better understanding  
13 of what the potential is within water, waste water agencies  
14 and work with government to bring renewables to the table.  
15 So we are working with some of the California Energy  
16 Commission staff, staff from the PUC, staff from our Aqua  
17 staff, a number of the waste water committee in order to put  
18 together a survey this summer that's trying to get at an  
19 understanding within the water and waste water sector of how  
20 much renewable energy, all different types, have been  
21 installed between 2001, and then how much more are water and  
22 waste water agencies currently projecting, and then trying  
23 to get at the same questions that you're getting at in terms  
24 of what are the obstacles that are preventing water and  
25 waste water agencies from doing well.

1       In accord with as we look at the partnership and the  
2 portfolio approach to try to get the State further to the  
3 goal line of achieving the 33 percent RPS there is, I think,  
4 a really unique opportunity to work with this particular  
5 sector that's going to be highly motivated to add a lot of  
6 capacity, to implement projects within the next five to ten  
7 years that could be an important layer in helping to achieve  
8 the goals.

9       And with that, I'd be happy to answer questions.

10       MS. DOUGHMAN: Okay, thank you.

11       And our last panelist is Dariush Shiromohammadi.

12       MR. SHIROMOHAMMADI: Thank you for pronouncing my name  
13 so well. That doesn't happen often.

14       I'm so glad to hear the presentation by other  
15 panelists, they cover so many of the important big picture  
16 issues that we need to keep in our sight and not lose sight  
17 of those important issues.

18       My presentation is going to be a lot more down to  
19 earth. And funny enough, I was thinking that my  
20 presentation will not be related to modeling. But when I  
21 look at it and especially when I put it in the context of  
22 other presentations, I see my presentation is all about  
23 modeling.

24       So once a geek, always a geek, I suppose.

25       One of the biggest issues here and, by the way, I

1 represent California Wind Energy Association, which  
2 represents wind developers in the State, many wind  
3 developers in the State.

4 One of the biggest issues, you know, we have to deal  
5 with is the fact that on matters as important as this  
6 studies are performed by multiple agencies, sometimes even  
7 multiple studies within the same agency, which are not  
8 coordinated well enough with each other, for a variety of  
9 reasons.

10 As somebody who worked in one of these agencies, and I  
11 was so lucky to get CEC help me quite a bit, and we could do  
12 some coordination there.

13 But we run through extraordinary efforts on the side of  
14 both CAL ISO and CEC to make that happen. It wasn't  
15 happening easily.

16 One of my concerns is we see all these studies, with  
17 all these -- which are by and large focusing on the same  
18 outcome. The scope is different, but if CAL ISO, for  
19 example, is focusing on the amount of additional regulation  
20 they need, and you're focusing on the cost of integration of  
21 renewables, and somebody's looking at the cost of fuel,  
22 there are a few on greenhouse gases, you by and large would  
23 be studying a similar case, getting different results out of  
24 it.

25 So saying that the scope of these studies are different

1 is not good enough, especially if the results come out in  
2 such a way that if I take the California ISO, the study on  
3 the amount of regulation I need, and I compare it with the  
4 study that CEC did on greenhouse gas reduction, and I see  
5 everything is different in them, that confuses me as a  
6 stakeholder, it confuses the public.

7 And, of course, CEC and CAL ISO are not the only  
8 entities who are doing these type of studies, CPUC does its  
9 own studies, and utilities, they do their own studies.

10 My concern is all these duplicative -- well, let me not  
11 call them duplicative, but all these complementary studies  
12 who, for a variety of reasons, do not start from the same  
13 point, do not end up -- which do not end at the same point,  
14 are at least confusing me as a stakeholder, and the  
15 constituents we have.

16 And as such, I'm sure that they will confuse the  
17 general public even more, especially as we just saw this  
18 morning, one entity says we're going to spend more gas, then  
19 another study says we're going to be burning less gas, and I  
20 guess both studies came out of the same -- the same  
21 organization.

22 So my point there is that we need to find a way of  
23 having, given that all of us are in the same boat, to put  
24 the resources together and try to do a one set or one  
25 consistent comprehensive study.

1       And especially avoid presenting results which may be  
2 completely -- the fact that they came off of a model doesn't  
3 mean that they should be presented.

4       The second point I'd like to make is what I've noticed,  
5 I was one of the central members of the NERC team, which  
6 worked on the -- and thanks, Danielle for bringing that up,  
7 made my life so much easier -- that studied the integration  
8 of large amount of renewables in the system, and we looked  
9 at it from reliability stand point.

10       Our first tendency was to look at, okay, this is the  
11 way the system is, this is the way we operate and plan, and  
12 operate it, what's going to happen if we increase all this  
13 wind, and solar, and all that stuff, ocean power and so on,  
14 what will happen to it?

15       Some of us, who have been in this business long enough  
16 say, no, no, no, hold on, the rules that dictate the  
17 planning and operation of the system were developed decades  
18 ago under very unique -- well, I can say, as a long-term  
19 transmission operator and planner, under simplistic  
20 conditions, to make the life of the operator and planner  
21 easier.

22       I mean, well, I must say we didn't have the  
23 mathematical tools to do better.

24       We are taking those rules, we're bringing them, all  
25 these models have them in them, inherent in them, and we're



1 saying what would it take to integrate a lot more renewables  
2 into that model?

3 And, of course, we see all kinds of funny results  
4 coming out on the other end.

5 We need to basically, fundamentally question what is  
6 going on, how the system is planning for build, operated  
7 today. And that's what we're doing as part of this NERC.

8 I mean, NERC, the most conservative organization when  
9 it comes to engineering and reliability issues, have agreed  
10 to fundamentally question all these matters. And we are  
11 going to do that, we're going to the next space and, of  
12 course, we'll continue to evolve in a significant fashion  
13 again before we do an analysis of what it takes to integrate  
14 renewables.

15 We've been planning the system based on old  
16 deterministic planning standards, and those old  
17 deterministic planning standards always come up showing we  
18 need a lot more transmission to integrate renewables, and  
19 they always show that with the given transmission we can  
20 integrate only so little renewables.

21 If we could fundamentally went to what everybody else  
22 does in planning any system, any system is planned based on  
23 probabilistic approaches, except for transmission, where we  
24 use deterministic approach.

25 And they came about, as I said, for reasons that

1   existed decades ago. A lot of people here weren't born when  
2   we came up with those rules.

3           And, of course, NERC agreed. One of the best things  
4   about this NERC Task Force is they approached the matter  
5   with a complete open mind, rather than the traditional  
6   approach that we utility types take. This is the way we  
7   operate the system, now fit within it.

8           The idea is, no, we need to question the way we've been  
9   planning and operating the system.

10          So I would like to say that a lot of studies we're  
11   doing have fallen, and the results I see are falling within  
12   the same trap, where we think that the system will be  
13   planned and operated in the same old way and as such, the  
14   results that we get are going to be significantly  
15   conservative, the costs will be significantly higher than  
16   they would be, and the requirements will be significantly  
17   higher for integrating renewables, than it would be.

18          So we need to question those fundamental rules.  
19   As we speak, CAL ISO is trying to work out a reserve sharing  
20   arrangement with BPA, which will help tremendously with  
21   integration of renewables in both service territories.

22          If we assume that that doesn't exist in our planning  
23   stage, our operational stage, or whatever integration  
24   studies we do, we are -- and by the way, NERC is working on  
25   modifying its rules, which are a combination of reliability

1 and economic rules, based rules. We like to think  
2 everything in their model is reliability, but it's not. To  
3 see what rule changes keeps the system reliable and allows  
4 for additional significant voluntary integration of  
5 renewable resources.

6 And in line, and the further point I'd like to make,  
7 and the last point I'm making, is and in line with that just  
8 observation, we need to stop looking at renewables simply as  
9 some random negative load. That's most of the integration  
10 sources studies they do that, unfortunately.

11 The new generation of renewable resources are as  
12 controllable, and as powerful in being controllable as any  
13 gas plant out there. It can provide you with regulation,  
14 within their capability they can provide you with reactive  
15 support, they can do a lot of things.

16 I'm not saying, assuming that they're going to be all  
17 fully controllable, but even assuming them to be ten percent  
18 controllable will make the results could be significantly  
19 different that we get today.

20 So we need to also be a lot more open-minded about the  
21 way these resources can contribute to the reliability of the  
22 grid, than we have done in the past, which is sometimes ends  
23 up with some results which are not consistent with common  
24 sense.

25 That's it, I thank you very much.

1 MS. DOUGHMAN: Commissioner Byron, did you have any  
2 follow-up questions for the panelists?

3 COMMISSIONER BYRON: I do have a couple and I'll take  
4 advantage of asking them now, just because I apologize, I'm  
5 going to go need to join a conference call at three o'clock,  
6 and you may all finish before I get back, but I will try and  
7 be back around 3:30.

8 I'm just skipping through some of my questions.

9 Mr. Kelly, you said something earlier about not  
10 believing the high CHP, and energy efficiency and RPS may  
11 not be achievable. But back to CHP, what do you attribute  
12 that lack of achievability to?

13 MR. KELLY: Well, a couple factors. Let me -- first,  
14 there's going to be -- if what transpires in the way the  
15 PURPA must-bias is suspended this year, there is going to be  
16 a period of time when new CHP is going to have kind of an  
17 uncertain vehicle about how they're going to come before,  
18 either whether it's going to be a contractual approach, or  
19 going to be some kind of feed-in tariff.

20 So there's going to be a period of time that people  
21 would just -- all development of CHP's going to stop.

22 Secondly, in the context of discussing a remedy for  
23 CHP, which is contractually based, an RFO kind of approach  
24 for bringing on CHP, there's a lot of focus on setting a  
25 standard for participation in that program, a certain

1 efficiency level, for example, or whatever.

2 Irrespective of that your CHP, you've got to meet a  
3 certain bar to be bidding into the CHP, because that's what  
4 we want from a GHG perspective.

5 The people that I've talked to, on the technical side,  
6 think that there's limited capability for new projects to  
7 come in if that bar is set too high. Or just because from a  
8 business perspective, if you're doing new CHP, you've got  
9 the electrical side that's got to negotiate a deal for the  
10 thermal host side.

11 The alternative for the thermal guys, I'm just going to  
12 put it in a boiler and I'll deal with it that way, but I can  
13 do it right away, but I can get it going and I'll run.

14 And right now we're faced -- a lot of businesses are  
15 facing that choice, and it's my understanding there are a  
16 lot of businesses that are in the process of actually  
17 changing out some of the existing CHP and putting in  
18 boilers, because of the certainty that it gives them from  
19 the business, from the thermal host side, food processors,  
20 or whatever. They know that they can at least get the  
21 energy that they need to run their plants.

22 So this absence of complete certainty, that I think has  
23 the potential of persisting for a while, is going to stall  
24 new CHP, for that's the first thing.

25 And the second thing is how much can you get in the

1 world to come to the fore, when you've got to bid into an  
2 RPS kind of, RFO kind of context.

3 Well, small businesses, hospitals, and so forth do  
4 that. I have doubts that they will do that. I mean, under  
5 standard offered contract it was relatively simple to do,  
6 right, you would have some consultant come to you and say,  
7 listen, here's the contract, here's the price, boom, boom,  
8 get it all, pull it all together and here you go.

9 If somebody has to put together a bid packet, and  
10 you're working with a hospital, or a jail, or whatever  
11 you're working with, any kind of institution like that, it's  
12 going to be measurably more complicated, I think, to  
13 initiate that process and get it completed, and put in your  
14 proposal and compete in that kind of context.

15 So I think that uncertainty's going to hurt CHP as we  
16 unfold over the next four or five years.

17 COMMISSIONER BYRON: Well, I'm quite concerned about  
18 this. I'm also concerned about some of the comments that  
19 Ms. Davis made about missing opportunities with solar limits  
20 on incentives. And we're missing an opportunity here, I  
21 think, with private capital and in the marketplace, and  
22 bring the very GHG reducing technologies to bear that we're  
23 looking for.

24 A quick answer, if you will, 700 to 800 megawatts in  
25 the last seven years, renewables, aren't you seeing -- won't

1 you concede that we're seeing some significant improvement,  
2 a lot of contracts have been signed of late.

3 MR. KELLY: There are lots of contracts.

4 COMMISSIONER BYRON: That's all?

5 MR. KELLY: I have not seen that much operational. I  
6 mean, I think this year I read a report, I think from the  
7 Energy Commission, that there was going to be 150 megawatts  
8 that they expected to energize this year.

9 COMMISSIONER BYRON: Well, given that, Mr. Zichella,  
10 this topic actually came up earlier, maybe in a slightly  
11 different context, about what I'll characterize as the  
12 permitting, and the contract, and the construction failures.  
13 You know, it's not a hundred percent guaranteed process when  
14 we initiate a renewable generation or transmission project,  
15 but yet you made some comments earlier about wanting to  
16 reduce the number of lines that we see, POU, IOU  
17 coordination of efforts.

18 Do you acknowledge that we might need to see some more  
19 projects than we'd care to, knowing that some of them will  
20 not come to fruition?

21 MR. ZICHELLA: Yeah, I think that's just prudent  
22 planning. I mean, in RETI we actually have done that.

23 COMMISSIONER BYRON: Right.

24 MR. ZICHELLA: We're looking at, I think it's 160  
25 percent of our RPS goals is what we've been planning for and

1     trying to plan some transmission for it.

2           The good news is a lot of the project interest is in  
3     areas with existing corridors and where the existing  
4     transmission assets are. And while it's true that we may  
5     have to go in and replace some towers, and do some other  
6     things, I mean, to upgrade our existing system, we can  
7     actually take advantage of a lot of what we have. And  
8     that's really good news for getting this done quickly.

9           New rights-of-way is really where you run into the  
10    problems with siting, and public comment. And if you can  
11    stay within existing rights-of-ways, and best of all worlds  
12    deal with upgrading existing infrastructure, that's so much  
13    simpler to deal with from the environmental conflict, from a  
14    local concern point of view.

15          In many ways, the local concerns are often much greater  
16    than the environmental issues are, where people don't want a  
17    transmission line running by their house, or whatever.

18          I mean, it seems to me this is one way to really reduce  
19    those kinds of conflicts and get stuff built more quickly.  
20    If we need some new lines and we are going to build some new  
21    lines, that's great, we should be using the existing  
22    corridors that we have because we've already chosen those  
23    for a good reason.

24          And while other states in the west have had problems  
25    with their corridor selection process through the Federal



1 process, through so-called 368 corridors, section 368 of the  
2 Energy Policy Act of 2005, California did a pretty good job  
3 selecting corridors in that process, and we're going to use  
4 those corridors, too.

5 So I do think we want to reduce duplication. We can  
6 take advantage of a lot of what we already have. That  
7 doesn't mean we're not going to make major upgrades to the  
8 system to accommodate lots of power, and including greater  
9 than 100 percent of what our RPS goals are.

10 COMMISSIONER BYRON: Other commenters were very good.  
11 Mr. Shirmohammadi, I'd like to thank you very much. I got  
12 your message, actually a couple of messages with regard to  
13 your comments, I appreciate them.

14 I'll defer back to you, Ms. Doughman. And again, I  
15 apologize, I'm going to have to cut out shortly. I hope to  
16 be back. But Ms. Brown will still be here at the dais, and  
17 Robert will as well. And I hope to be back, too.

18 MS. DOUGHMAN: I just have one follow-up question. I  
19 didn't -- I'd like to ask the panelists to share your  
20 thoughts on question 12, "what impact will the exhaustion of  
21 above-market funds from the CPUC for two of the three IOUs  
22 have on California's ability to meet the 33 percent RPS  
23 goal?"

24 I think some of you mentioned it in your comments, but  
25 if you could just go over your thoughts on that again, that

1 would be helpful.

2 MS. OSBORN MILLS: This is Danielle Osborn Mills,  
3 again. I think two things need to happen in order to figure  
4 out what will happen if the above-market funds are  
5 exhausted.

6 The first is that I think we need some clarity.  
7 Resolution E4199 states that if the above-market funds  
8 balances, and it sort of neglects to answer the question of  
9 what happens to utilities' compliance obligation once the  
10 above-market funds are used up.

11 So know that while the IOUs are not required to procure  
12 any new renewables about the IPR, they're still encourage to  
13 procure below the NPR, but it doesn't necessarily state  
14 whether they still have a compliance obligation to meet 20  
15 percent. So we need some clarity on that.

16 I think, second, what we need to do is establish  
17 some criteria for project viability, which I know the CPUC  
18 is already working on. But we need to take a good, hard  
19 look at what some of the contracts are and how they're --  
20 whether or not they're underway and whether or not they're  
21 going to be built.

22 So we need to look at commercial experience, financing,  
23 some regulatory challenges, and find out which contracts are  
24 using the above-market funds, and whether they'll actually  
25 be build.

1           And I also think this is something that we should  
2 consider fixing in the 33 percent RPS.

3           MR. KELLY: This is Steven Kelly, with IEP. And I  
4 think assuming no change in State law, which is obviously  
5 being discussed as we speak, the effect is that the  
6 discretion to enter into new renewable contracts, or forward  
7 utility-owned generation contracts, or projects is going to  
8 be a discussion of the utilities, they don't lose that. And  
9 then the Commission will have to determine whether it wants  
10 to go forward with those or not, at that time.

11           It probably, you know, will make it more difficult to  
12 move projects forward.

13           I agree that if there are projects that have executed  
14 agreements and are not moving forward, and it's been a  
15 period of time so that there's no likelihood that they are  
16 going to go forward, we ought to figure out a way to maybe  
17 free that up.

18           Either expanding the size of the pot so that the  
19 contract that's been executed isn't harmed, I'm not  
20 interested in doing that at all. But if it's going to be a  
21 lengthy period of time and there are resources that we can  
22 reconfigure to move projects that are more viable, we should  
23 consider ways to do that without abrogating contracts.

24           IEP has worked very closely with the Commission on the  
25 project viability, which is designed to help inform that

1 process that could be used.

2 MR. ZICHELLA: I don't really have anything to add to  
3 that.

4 MR. SHIROMOHAMMADI: I'll pass.

5 MS. DOUGHMAN: Jeffrey?

6 MR. HAHN: Well, we're just hopeful that the  
7 legislation currently pending will reform the process, the  
8 RPF funding process.

9 MS. DOUGHMAN: Can you expand?

10 MR. HAHN: Well, get more money for renewables, change  
11 that market reference price.

12 MS. DAVIS: Yeah, this is Martha. I think that getting  
13 to a point where do for a green price, or the market  
14 reference price would be very important. But it isn't just  
15 that price.

16 I think that making sure there are an array of  
17 mechanisms by which projects can recover the full value of  
18 their investment, the net programs.

19 But what it is now is almost a smorgasbord of options  
20 that allow investors to look at what combination would end  
21 up looking best for them to ensure that it's moving forward  
22 with renewable energy projects.

23 For some, particularly, other agencies, the water and  
24 the waste water agencies, the net programs have actually  
25 been proving very effective at being -- for those programs

1 to be in place.

2 MS. DOUGHMAN: Okay. I'd like to open things up, now,  
3 to any questions we have from the audience in the room.

4 MR. ELLIS: I'm Jack Ellis, here for WPTF.

5 Several of the presenters talked about feed-in tariffs,  
6 and I believe you talked about the adequacy of compensation  
7 for your biomass projects.

8 And I guess there were also some talks this morning  
9 about the need for system resource flexibility.

10 I wonder if those of you who advocate feed-in tariffs  
11 could talk about how they would work in an environment where  
12 we need as much flexibility from the resources that we  
13 connect to the grid as possible.

14 MR. DAVIS: Speaking from the market data, speaking  
15 from our agency's perspective, the feed-in tariffs have  
16 been, particularly for the smaller size projects, if you  
17 look at the projects that it's moved forward, the big gaps,  
18 if you will, are the programs that have been in the ten  
19 megawatt range.

20 And a lot of that gets at two issues. One is the issue  
21 of the value of the NPR.

22 But the second is the need for a simple tariff, and  
23 paperwork, and simple inter-connect agreement.

24 So that for a three megawatt project you're not going  
25 through hundreds, and hundreds, and hundreds of pages of

1 contracts.

2       So coming up with a feed-in tariff that can be  
3 appropriately scaled to take advantage of a lot of the  
4 smaller projects, in and of themselves, they're not going to  
5 be the silver bullet on achieving the 33 percent RPS, but  
6 they clearly can play a very significant role as total  
7 portfolio approach. And to make it work, you have to have a  
8 feed-in tariff that is scaled to the size of the project.

9       MS. KELLY: Jack, this is Steven Kelly, again.

10       First, assuming the State has the authority to  
11 implement a feed-in tariff, which is being discussed, there  
12 are -- there are actually two structures for a feed-in  
13 tariff, one is what I call a standard contract, you sign the  
14 contract, off you go.

15       The other is you get paid when you deliver to the grid  
16 and here's what you're going to get paid, and you really  
17 don't have a contract. You use kind of a tariff basis from  
18 some mechanism to pay people.

19 Under both those structures, whichever approach it's taking,  
20 in order to deal with the variability issue that you've  
21 described, I think you can -- it's not the case that you  
22 need to have, necessarily a single price across all  
23 technologies, because all these different renewable  
24 technologies can provide a different product, essentially.  
25 Some can provide base load, some might be able to conjure up

1 a little load following, and so forth, all of which might be  
2 priced at a slightly different level.

3 And I think you could use the pricing signals of a  
4 feed-in tariff to moderate the integration of the new  
5 renewables over time, to minimize the reliability issues  
6 that might pop up.

7 You can set a cap for the number of megawatts that  
8 might come through that kind of structure, as well, to help  
9 moderate reliability concerns.

10 And I think you can use it as kind of a -- I think of  
11 it as using it of kind of a toggle or a baffle to moderate  
12 the flow of the renewables through that structure.

13 I look at a feed-in tariff as a complement, not a  
14 replacement to the RPS/RFO structure, as well, so you can  
15 set it and see which one -- California's position, to  
16 actually experiment with those and see which is more  
17 effective in bringing on viable renewables in a quicker time  
18 frame, and assuming we can actually do a feed-in tariff  
19 under the law.

20 MR. ZICHELLA: Yeah, the point I was trying to make  
21 about feed-in tariffs is we are going so slowing with  
22 distributed generation, it's really painful to watch.

23 And if we're going to have an impact on how much remote  
24 renewables we're going to need, and how much transmission  
25 solutions we need to move that much remote renewables to the

1 load centers, we need to look at how we can really  
2 accelerate what it is that we're doing.

3 And the way our incentives are structure right now,  
4 there's real limits on what people can do. Whether you own  
5 a large commercial structure or you own a home, there are  
6 limits to how much you can generate. And with net metering,  
7 especially at the smaller end of things, you know, no one's  
8 going to put a system on their house, that they have to  
9 finance, themselves, if they can't sell their excess power  
10 back to the grid.

11 So, you know, as far as the reliability questions go,  
12 you know, I think there are going to be reliability issues  
13 with it, but it is a very useful power source that does not  
14 require these really intensive, difficult transmission  
15 solutions to wield, and we can really ramp up a greater  
16 percentage of what it is we're trying to accomplish here  
17 with renewables, if we can come up with the right sweep of  
18 incentives in order to do that.

19 Feed-in tariffs give you that kind of investment  
20 assurance. You can get financing. If you know you're going  
21 to be able to get a certain price for a certain period of  
22 time, for example, as Steve just said, there are ways to  
23 adjust tariffs.

24 In fact, in Germany they do have technology-specific  
25 pricing. Spain has set caps, as Steve described.



1           We have models to look at out there, we don't have to  
2 completely come up with them, ourselves.

3           I think that the possibility of enacting one at a State  
4 level is very good. There's a fair amount of belief that  
5 the State already has the authority to do feed-in tariffs,  
6 but there's interest at the Congressional level to clarify  
7 that, to make sure that states have that authority. Whether  
8 it's as a component of compliance tools and how to implement  
9 a national, renewable electricity standard, or just a free-  
10 standing bill, as Representative Inslee has proposed for  
11 feed-in tariffs, I think those issues are going to be  
12 clarified.

13           As far as the grid reliability issues, I think it's  
14 going to have to be viewed in the context of the entire  
15 portfolio.

16           MR. ELLIS: Go ahead.

17           MR. SHIROMOHAMMADI: I'd like to make a point related  
18 to this issue. While I know exactly what you're saying by  
19 bringing up the issue of feed-in tariff, that's one way of,  
20 as you say, putting certainty, rate certainty, investment  
21 recovery certainty to renewable developers.

22           If looking at the California ISOQ, or Midwest ISOQ,  
23 generation Q, is any indication, there seems to be  
24 incentives out there. Additional incentives are always good  
25 and people, a lot of renewable developers are using the

1 existing program, existing regime to bring in the ware to  
2 the market.

3 If there is any -- to me, if there is any of those  
4 expenditures that could a lot more significantly promote  
5 renewable development than paying one way for development,  
6 or one megawatt for rooftop solar, or whatnot, is of --  
7 payment guarantees for technologies that help with  
8 integration of renewables.

9 We're talking about, for example, storage, where maybe  
10 there could be some sort of a payment guarantee, or feed-in  
11 tariff for developing storage, or transmission lines and so  
12 on.

13 So I know I took this a bit farther than what you  
14 wanted to hear, but what my thinking is, if the purpose of  
15 providing investment guarantee, I think they would probably  
16 get more out of it if they are made in the areas where it  
17 helps the existing developers, even to help them with --  
18 give them additional incentive to bring the power into the  
19 system.

20 MR. ELLIS: Well, let me follow up with another  
21 question, then. If we --

22 MR. HAHN: Do I get a chance?

23 MR. ELLIS: Oh, I'm sorry, go ahead.

24 MR. HAHN: Just because we're based loaded, we tend to  
25 forget about us.

1 MR. ELLIS: Actually, you're the one I had in mind.

2 MR. HAHN: I have my cheat sheet from Julie here, if  
3 you'll pardon me for reading.

4 Again, the advantages to the IOUs, the long-term  
5 stability of the installation from volatile fossil fuel  
6 prices, and the retention of existing renewable biomass base  
7 of generation, and part of that comes -- and, obviously,  
8 these are our suggestion, because SRAC has been below seven  
9 cents a kilowatt hour since October of 2008. So we're  
10 really getting hurt on that, for the plants that have SRAC.

11 What we have proposed is a new fixed-price agreement  
12 starting immediately, no later than 1/1/10. Open season for  
13 enrollment, open to all biomass plants. The end of capacity  
14 payments it received, and also the end of capacity liability  
15 is dissolved.

16 A production guarantee posted equal to three months of  
17 gross revenues. The term's so that the contract run the  
18 shorter of the current contract or 12 years, and start at  
19 9.35 cents per kilowatt hour, and escalate at 2 and three-  
20 quarters percent a year.

21 So that would keep the biomass industry running, you  
22 know, if we can have this come out. But if continues as it  
23 is today, we won't be viable if the electrical -- what we're  
24 paid for electricity is a lot less, like where SRAC is now.

25 MR. ELLIS: Thanks.

1 MS. DOUGHMAN: Are there any more questions from the  
2 audience?

3 MS. KOROSEC: Pam, I do have some public comments that  
4 I need to read into the record. They're not specific to  
5 this panel, they're just more on the broad topic of  
6 integrating renewables.

7 A public member was not able to attend and asked that  
8 these three paragraphs be read into the record.

9 "The proponents who believe global warming is caused  
10 mainly by manmade greenhouse gas have convinced Governor  
11 Schwarzenegger and the California State Legislature to  
12 mandate that investor-owned electric utilities in the State  
13 sell electricity generated by renewable energy resources.  
14 The mandate for 20 or 30 renewable cases several problems.  
15 First, a 20 or 30 percent reduction is a Band-aid approach  
16 when, to be effective, an 80 to 100 percent reduction is  
17 required to have a meaningful effect on warming.

18 Second, there's no way that the energy sources mandated  
19 by the Legislature can provide 24/7 reliable electricity in  
20 the amounts that the public and industry require. The sun  
21 shines a limited time per day, wind energy is fickle, both  
22 are diffuse and require large installations to produce small  
23 amounts of electricity. They can be used only if they're  
24 backed up by reliable energy sources, a very expensive  
25 operation.

1       The CEC can hold workshops on how to overcome the  
2   deficiencies of renewable energy from now until doomsday,  
3   but there's simply now way that the CEC can juggle the  
4   effects of energy conversion to make renewable energy an  
5   economical or meaningful way to reduce greenhouse gas  
6   reduction in meaningful amounts.

7       An 80 to 100 percent reduction in greenhouse gas  
8   reduction could be accomplished by using nuclear energy, but  
9   the CEC is not willing to tell the Legislature that this is  
10   the only practical way to achieve that goal. There is  
11   always lurking in the background the question of whether  
12   global warming is really due to manmade activity and, thus,  
13   whether all of this agonizing is futile."

14       MS. DOUGHMAN: Any reactions from panelists?

15       MR. ZICHELLA: Well, it's not legal to build nuclear  
16   power plants in California right now, for one thing. And  
17   for another thing they're more expensive to build for real  
18   dollars, in real dollars, than they were in the 1980s. You  
19   can hardly find a more controversial siting problem.

20       If we think that transmission siting is problematical,  
21   you ain't seen nothing, yet.

22       I think this is technology that still has the same  
23   flaws it had 50 years ago, it still hasn't solved any of its  
24   major problems. So I can't see us making a major  
25   contribution, from nuclear power, to solve global warming

1 under any circumstances. Not the least of all, you know,  
2 the only forge that's capable of building nuclear reactor  
3 vessels in the world is in Japan. We're not going to be  
4 building a lot of nuclear power plants.

5 MS. DOUGHMAN: Any other comments from panelists.

6 MS. DAVIS: I thought that was succinct.

7 MS. DOUGHMAN: We can't hear you very well, Martha, can  
8 you increase your volume?

9 MS. DAVIS: I thought that was succinct.

10 MS. DOUGHMAN: Succinct, okay.

11 MR. ZICHELLA: That's something I don't often get told.

12 MS. DOUGHMAN: Any more questions from the dais?

13 MS. BROWN: No, but are there other public comments  
14 from anyone in the audience?

15 MS. DOUGHMAN: On WebEx or on the phones?

16 MS. KOROSEC: All right, all lines are open on WebEx,  
17 if you'd like to make a comment?

18 Hearing none.

19 MS. DOUGHMAN: I think we're ready for closing comments  
20 from the dais.

21 MS. BROWN: Okay. Well, for those of us remaining, we  
22 do appreciate everyone's participation today. I think we  
23 covered a wealth of subjects, starting this morning with the  
24 utility presentations, we heard about logistics, we heard  
25 about the costs, we heard about the PUC's efforts to put

1    their arms around some of the costs and benefits of  
2    renewable energy.

3           And I was especially interested in the panel this  
4    afternoon on some of the issues that you see, some of which  
5    we've heard before and we continue to work on these issues,  
6    right, the feed-in tariff, the net metering, the contracting  
7    issues.

8           I didn't hear a lot about regulatory streamlining or  
9    permitting, but I think that still remains an issue for the  
10   large solar thermal plants.

11          So I didn't have anything further.  Again, on behalf of  
12   Commissioner Boyd, we thank you for being here.

13          Bob, did you want to comment?

14          MR. KINOSIAN:  I just wanted to thank everybody, I  
15   thought it was a very informative workshop today.

16          MS. BROWN:  Great.  And we appreciate Commissioner  
17   Byron being represented, as well.

18          So I think with that, we stand adjourned.

19                 (Whereupon, at 3:12 p.m, the Joint  
20                 Committee Workshop was adjourned.)

21                                 --oOo--

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