JOINT INTEGRATED ENERGY POLICY REPORT AND RENEWABLES

COMMITTTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	Docket No.
Preparation of the 2009 Integrated	)	09-IEP-1G
Energy Policy Report	)	
	)	Docket No.
	)	03-RPS-1078
	)	
	)	
______________________________________	)	

“ELECTRICTY SYSTEM IMPLICATIONS OF 33 PERCENT RENEWABLES”

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 9TH STREET

SACRAMENTO, CALIFORNIA

MONDAY, JUNE 29, 2009

9:06 A.M.

Reported by:
Peter Petty

CALIFORNIA REPORTING, LLC
52 LONGWOOD DRIVE
SAN RAFAEL, CA 94901
415-457-4417

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

Dariush Shirmohammadi, California Wind Energy Association

Danielle Osborn Mills, Center for Energy Efficiency and Renewable Technologies

Jeffrey Hahn, Coventa 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

I n d e x

I N D E X (Cont.)

P R O C E E D I N G S

9:06 A.M.

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

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

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

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

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

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

Today's workshop is being broadcast through our WebEx conferencing system. Parties should be aware that we are recording the workshop. I will make the recording available on our website immediately after the workshop and then we'll also provide a written transcript, once that becomes available, which is usually about two weeks after the workshop date.

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

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

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

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

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

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

This workshop's being held as part of the 2009

Integrated Energy Policy Report, or IEPR proceeding.

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

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

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

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

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

And in the 2008 IEPR we began the analysis of what it would take for the system to be able to support that level of renewables. And we also committed to continuing that discussion in the 2009 IEPR, which is why we're here today.

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

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

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

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

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

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

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

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

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

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

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

This is another important workshop in the IEPR process.

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

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

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

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

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

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

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

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

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

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

We can’t really anticipate the technology develop, nor the cost of that accurately.

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

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

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

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

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

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

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

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

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

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

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

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

COMMISSIONER BYRON: Very good, thank you, Ms. Brown.

Mr. Kinosian?

MR. KINOSIAN: Thank you. Unfortunately, Commissioner Bohn couldn't be here today. He also has a very keen interest in the topics that are going to be addressed here today. In particular, he thinks that it's critical that as we move ahead on the ambitious State goals that we do so in an informed manner and, hopefully, in an intelligent manner.

And that it is very important that the policymakers, and not just the policymakers, but the ratepayers understand what the impacts of these policies are.

Thank you.

COMMISSIONER BYRON: Very good.

Commissioner Levin, are you with us?

MS. KOROSEC: It sounds like she's not on, yet, so we'll check periodically through the day. Perhaps as we go through each panel we'll check before we --

COMMISSIONER BYRON: Yes, I think she's about eight or nine hours ahead of us.

MS. KOROSEC: Yeah, I think so.

COMMISSIONER BYRON: So if she does come online and you see her, please let me know.

MS. KOROSEC: Well, unfortunately, with the call-in system it doesn't identify the person's name; it only identifies the users, so that's why we'll need to check periodically.

COMMISSIONER BYRON: All right.

MS. KOROSEC: All right, thank you.

COMMISSIONER BYRON: All right. Well, let's proceed. I note that the first person on our agenda is Ms. Griffin, the California Energy Commission, Introduction, "Electricity System Implications of 33 Percent Renewable Energy."

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

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

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

And then there was this thing, ancillary services, which the guys in the back room kind of handled. Well, as the system has gotten more sophisticated and we're adding many more kinds of resources and many more kinds of players, these system support functions have become absolutely critical.

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

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

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

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

Each one has its own framework; it has its own objectives and time. You might think that in an ideal sort of world we'd finish one study, we'd learn form it, we'll move onto the others; but we're kind of in a hurry here and so each party is trying in their own way to figure out a piece of the problem.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MR. MINICK: Last week.

COMMISSIONER BYRON: I hope you got a weekend?

MR. MINICK: I did, actually.

COMMISSIONER BYRON: Thank you for being here.

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

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

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

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

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

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

MR. ALVAREZ: Yes.

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

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

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

MS. GRIFFIN: Is Joe Eto on the phone?

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

So I'd like to start with Antonio.

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

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

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

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

And in our approach we're looking at ancillary services in three buckets. We're looking at regulation, we're looking at load following, and we're looking at resources that need to be available for the commitment uncertainty.

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

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

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

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

We don't look at transmission or look at the additional cost of renewables, that's -- you know, other studies are doing that we thought that we probably added more value by looking at the integration question.

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

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

MS. GRIFFIN: Are there questions from the dais?

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

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

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

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

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

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

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

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

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

MR. ALVAREZ: Okay.

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

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

But what I'm saying is that in the same way we develop a tool that looks at integration based on the cost of conventional resources that are used to integrate intermittent generation.

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

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

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

MR. ALVAREZ: Right.

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

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

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

MR. ALVAREZ: That's correct.

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

MR. ALVAREZ: There was one interesting takeaway that we have, which is that there is a point in time, a point as you add more intermittent resources that where you have the need for additional flexible resources that aren't provided, in excess of the reliability requirement of the system.

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

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

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

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

Now, we plan to calibrate the tool, working with the ISO as part of the 33 percent integration study, so that we're able to better determine what is the ability of the existing system when you have, for example, 15 percent planning reserve margin what can you integrate? What level of intermittent generation you can integrate, what type of resources you can integrate and up to what point with the current planning reserve margin.

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

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

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

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

COMMISSIONER BYRON: And this tool will be available publicly?

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

COMMISSIONER BYRON: Thank you.

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

MR. ALVAREZ: Okay.

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

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

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

And so you can -- just to answer your question directly, we looked at the uncertainty of load forecast and the generation, uncertainty for intermittent generation.

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

MR. ALVAREZ: Right.

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

MR. ALVAREZ: Right.

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

MR. ALVAREZ: Right.

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

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

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

Having said that, you can run the mull, you know, very quickly by first adding the load and then adding increments of intermittent generation, and then you can estimate the incremental affect of say wind or solar added on top of the load forecast error.

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

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

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

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

MR. ALVAREZ: Right.

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

MR. ALVAREZ: Yes, right. Again, the forecast error is a user input defined and so you can look at different scenarios. You know, look at for example in the future, if you anticipate a reduction in your errors, you can account for that in the tool.

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

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

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

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

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

MS. GRIFFIN: And who does these forecasts; is it the control area, the balancing authority, or is it the load-serving entities, such as PG&E?

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

And I’m sure David Hawkins can speak about it more eloquently than I can.

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

MR. ALVAREZ: That’s right.

MS. GRIFFIN: Right.

MR. ALVAREZ: Right.

MS. GRIFFIN: Are there questions from the group?

You’re just going to have to come up.

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

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

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

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

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

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

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

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

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

MR. ALVAREZ: That's right.

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

MR. ALVAREZ: That’s right.

MR. ELLIS: -- by either you, or the utilities, or the ISO, or perhaps a combination of the two to look at those options?

MR. ALVAREZ: Right.

MR. ELLIS: Okay, thank you.

MS. GRIFFIN: I had one more question. Are you planning to introduce this tool at the PUC and the Planning Reserve Margin proceeding, when that thing kicks back up again?

You’re -- one of your findings was you needed a higher PRO and so --

MR. ALVAREZ: Yes, I think it will have to be introduced somehow. I’m hesitant because I know that the tool that so far has been used is a GE/MARS model, and MARS uses -- basically assumes that whatever generation is there is available, you know, kind of ignores the forecast error.

So what we’re going to find, you know, the results that we’re going to find using the tool are going to ignore the operating requirement. And so this will have to be kind of layered somehow on top of that and trying to figure out exactly how to do it at this point.

MS. GRIFFIN: Okay, but that’s an important finding for working on integration.

MR. ALVAREZ: That’s right.

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

MR. ALVAREZ: Yes.

MS. GRIFFIN: Okay.

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

MR. ALVAREZ: Hi, Steven.

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

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

MR. ALVAREZ: Um --

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

MR. ALVAREZ: Yeah.

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

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

MR. KELLY: Yeah, right, above --

MR. ALVAREZ: I'm starting from zero.

MR. KELLY: Okay.

MR. ALVAREZ: So if you add 2,000 megawatts over what we have today, it would be about 20 megawatts more of regulation.

MR. KELLY: And what does it take to provide that? I mean, is that like a combustion unit or something that's one 50 megawatt gas-fired unit to do that?

MR. ALVAREZ: I would say it's a unit that can be on automatic dispatch, that can basically have enough head room that it can go up and down as a function of frequency.

So it could be a combined cycle, for example, that's operating above the minimum generation.

MR. KELLY: And this would be just seeking another 20 megawatts from that unit to support the wind?

MR. ALVAREZ: Right, right.

MR. KELLY: And then on the load following the same thing, I'm looking at page 9, just so I understand this; if you went to basically 4,500 new megawatts of wind in Tehachapi, the support for that would be a hundred megawatt --

MR. ALVAREZ: Right.

MR. KELLY: -- load following characteristics would be some sort of combined cycle?

MR. ALVAREZ: Yeah.

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

MR. ALVAREZ: Yes.

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

MR. ALVAREZ: Right.

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

MR. ALVAREZ: Yes.

MR. KELLY: Okay, good. Thanks.

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

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

MR. ALVAREZ: You're welcome.

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

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

MR. BLUE: Hi you doing. Following up on Jack's, the first speaker's comment about some geographic diversity, and I know that WestConnect, which is a group of utilities in the southwest are looking together at a AGC sharing type of an arrangement.

MR. ALVAREZ: Right.

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

MR. ALVAREZ: Right.

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

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

So I think it is possible to do.

MR. BLUE: All right.

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

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

MR. ALVAREZ: Right.

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

MR. ALVAREZ: Great.

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

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

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

MR. ALVAREZ: Okay, thanks, Greg.

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

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

MR. ALVAREZ: Okay.

MR. BROWN: You had a statement on finding the conclusions that today's preferred resources, which are energy efficiency, demand response and distributed generation do not help integrate intermittent resources.

That seems a fairly broad statement to make.

MR. ALVAREZ: Right.

MR. BROWN: And so I was curious, are there caveats on that, are there qualifications that you came to that conclusion from this study; so could you elaborate, please?

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

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

MR. ALVAREZ: Right. Yeah, thank you.

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

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

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

MR. BROWN: Okay, thank you.

MR. ALVAREZ: Sure.

COMMISSIONER BYRON: Mr. Brown, thank you for bringing that up. I have to say when I read that finding or conclusion that today's preferred resources, meaning energy efficiency, demand response, and distributed generation do not help integrate intermittent resources, it was very troubling.

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

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

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

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

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

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

COMMISSIONER BYRON: Agreed.

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

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

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

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

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

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

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

MS. GRIFFIN: Were there questions on the WebEx?

MS. DOUGHMAN: No.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

There were palms in that database about minimum loads, ramping times and things like that, that were in the database that hadn't been cleaned up, yet. TEPPC has since cleaned up their database some, so it's a little better database.

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

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

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

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

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

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

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

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

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

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

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

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

We found in a few cases 18 percent was inadequate to meet what the model was saying was the ramping requirements for certain hours.

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

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

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

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

We deviated slightly from that methodology. And everybody's going to ask how? We counted wind as ten percent capacity contribution, we counted solar in around the 55 to 65 percent range, it depends on the solar. Unless it had solar thermal with storage, meaning it had stored enough energy in the morning that it could produce at full output at the time of the peak then it was more like 95 percent.

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

So this is their capacity contribution towards the planning reserves.

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

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

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

We imported about 3,800 megawatts of either RECS or imported power.

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

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

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

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

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

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

We limited our imports to a certain amount from other states.

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

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

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

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

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

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

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

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

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

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

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

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

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

We found that we needed nine new transmission lines, that's total of nine. Some of those have already been started. The Sunrise Project's already been approved, but it’s not built yet.

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

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

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

So we’re looking at new transmission lines.

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

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

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

So we had hours when we had dump energy. Dump energy being defined as we could not find a home at any price for energy, meaning there is no place to put it. That’s why we've got to look at storage options so we can shift this energy usage.

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

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

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

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

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

We did not think we could build all the transmission necessary to put all this together by 2020. And E-3 is coming to a similar study for the PUC, saying maybe 2024. I've only briefly read their study, I've been on vacation for a couple of weeks.

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

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

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

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

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

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

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

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

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

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

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

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

Too many of those is going to cause some interesting portavations (phonetic) on my system if I haven't got it back up with some battery storage or something else that can cover for it.

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

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

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

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

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

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

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

Therefore, we have to go back and take a look at that, because when everybody wants to be connected to the grid, we don’t want a single or multiple contingency to bring the whole grid down. We did not analyze that.

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

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

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

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

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

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

In real life it isn’t that simple. We don’t have a production simulation model. And we looked at ten-minute simulations, in some instances, that can predict perfectly kind of how the model works.

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

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

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

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

Other questions from the dais?

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

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

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

MR. MINICK: We’ve made all the input assumptions available a while ago. We will make the conclusions available.

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

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

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

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

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

MR. MINICK: Well, yeah, you'd probably need less transmission lines, you’d probably -- see, we’d have to go back and take a look at it.

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

MS. GRIFFIN: Uh-hum.

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

MS. GRIFFIN: Uh-hum.

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

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

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

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

MR. MINICK: Well, again --

MS. GRIFFIN: Fewer lines to build.

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

MS. GRIFFIN: Okay, questions from the audience?

COMMISSIONER BYRON: Mr. Brown, come forward.

And Mr. Kinosian has a question, as well.

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

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

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

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

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

So there are slight differences. I can't say that this is an end-all, it's just sort of a kickoff for more studies.

MR. KINOSIAN: Okay.

COMMISSIONER BYRON: Dr. Brown?

MR. BROWN: Yeah, Merwin Brown, with California Institute for Energy and the Environment.

A number of times you made the statement that there are a lot of problems with meeting the 33 percent or higher, with the grid operational problems, economic problems, and things like that, and you said but we can do it.

And so what I'm interpreting it is you are probably saying that we can keep the lights on, but there must be some kind of cost to that, or a penalty, or extraordinary actions taken. I was wondering if you could elaborate by what you meant by that?

MR. MINICK: The study's way of doing it was simplistic. It assumes that you'd store a lot of this energy when it was generated in surplus and use it for times when you needed it for various purposes, and you'd build very quick responding peakers, maybe more than you totally need. But again, this was our way of kind of solving it in the short term.

When I say problems, they're not -- it's all these things are issues, let's just say, that need to be resolved by consensus building throughout the State and how do we get there?

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

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

MR. MINICK: Yes.

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

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

MS. BROWN: Yes, all those costs.

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

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

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

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

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

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

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

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

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

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

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

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

MR. ZICHELLA: Okay, great. I’m sorry, I misunderstood.

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

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

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

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

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

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

MS. GRIFFIN: Anybody on the web?

MR. MAGALETTI: One more question, please?

MS. GRIFFIN: Okay.

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

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

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

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

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

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

MR. MAGALETTI: Thank you.

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

MR. MINICK: Thank you.

MS. GRIFFIN: Okay, thank you.

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

MS. GRIFFIN: Yes.

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

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

COMMISSIONER BYRON: Are you sure?

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

MR. PLETKA: Okay. Can you hear me?

COMMISSIONER BYRON: Yes.

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

UNIDENTIFIED SPEAKER: Yes, you have control now.

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

MS. GRIFFIN: Ten minutes.

MR. PLETKA: Okay.

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

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

COMMISSIONER BYRON: All right, thank you.

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

MS. GRIFFIN: Yes.

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

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

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

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

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

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

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

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

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

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

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

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

There are a lot of stakeholders in the RETI process, so certainly it's been very helpful to have the input of all these different groups, all the transmission providers, or the major transmission providers and load-serving entities in the State, as well as representatives from the generators, public interest groups, like the Sierra Club, and the various permitting agencies.

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

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

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

The intent is that after there's some consensus agreement on what the conceptual transmission network will look like, then the utilities or other project proponents will then develop detailed plans of service for specific lines that are part of the conceptual transmission plan and that will then go into the permitting process.

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

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

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

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

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

So as part of the Western REZ process we now have kind of a consolidated dataset that puts renewables on kind of a comparable basis state by state by state.

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

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

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

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

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

So that RETI net short, there's a formula there that really does, you know, here's the sales in California 2020, here's the RPS requirement. And then we take out operating resources, the Go Solar Initiative, various other things to arrive at an all-in number of about 60,000 gigawatt hours per year needed by 2020.

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

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

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

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

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

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

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

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

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

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

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

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

And phase one was known to range from zero to 12 in terms of the relative environmental concerns.

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

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

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

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

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

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

Thank you very much.

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

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

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

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

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

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

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

COMMISSIONER BYRON: Excellent, thank you.

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

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

MS. GRIFFIN: No.

COMMISSIONER BYRON: How about from the audience?

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

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

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

(Off the record.)

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

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

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

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

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

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

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

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

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

COMMISSIONER BYRON: Dr. Ryan, welcome back.

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

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

MS. RYAN: Which one is that?

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

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

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

And speaking of our staff, let me take a moment to recognize Angelette (phonetic), and Jaclyn Marks, who are sitting in the audience today. Not to put them on the spot after I leave, but just to acknowledge the very hard work that they and others put into this study, which I have the privilege to present to you.

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

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

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

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

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

Such as “forget logistics you lose,” from one of General Schwartskopff’s Desert Storm corp commanders.

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

(Laughter.)

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

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

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

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

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

And so our point of departure was that to get to 20 percent in 2020 we would need to slightly more than double existing renewable generation from 27 terawatt hours per year in 2007, to 35 terawatt hours per year in 2020.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

So timeline number 1 is, in a sense it's already the past. This is a timeline which shows each line in here is essentially a renewable energy -- is a renewable energy zone. And each sequence of colored bars, end to end, represent all the various steps in bringing the energy in that zone to market.

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

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

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

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

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

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

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

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

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

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

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

Now, returning to military history, not Clausewitz, I thought it was him, but it was actually the Prussian Chief of Staff, Field Marshall Moltke once said, and people have often heard this one, “no battle plan survives contact with the enemy.”

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

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

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

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

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

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

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

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

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

Not just the parallel processing for individual projects, but moving all these projects through the siting, permitting, construction interconnection process at the same time.

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

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

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

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

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

We could focus more on distributed solar PV, which does not require new transmission so it removes one risk but, you know, substitutes others.

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

So those are examples of things that we might do.

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

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

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

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

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

The high DG case, a lot more solar PV. And generally, as you go from less to right, there's less solar thermal.

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

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

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

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

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

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

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

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

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

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

So the absolute difference in dollar terms, in the cost of that case relative to the 20 percent RPS case, and then it's also expressed in percentage terms.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

So and then along the bottom, statewide electricity expenditure.

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

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

And I think the one major takeaway here is that even at a very high gas price and allowance price the 33 percent RPS is still a little bit more expensive than the all-gas scenario, and a little bit more expensive than the 20 percent RPS reference case.

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

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

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

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

And what you can see here is, again, the 20 percent RPS reference case and 33 percent reference case contrasted in the first two lines, the total of statewide expenditures in those two cases under the base case assumptions, and then under the low load sensitivity.

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

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

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

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

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

And from an environmental perspective that's still desirable, but from an economic perspective it says now we're not saving money anymore, we're not avoiding the cost of building new plants by building a renewable plant, or we’re not avoiding the cost yet, so we’re retiring, essentially shelving a useful asset. So that makes the 33 percent RPS case more expensive relative to the 20 percent case, in which it is still the case that all additional renewables do drive out new investment -- investment in new fossil-fired plant.

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

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

And what we explore in this case is, well, what if -- what if what the industry is telling us they can do they do, they do do it and it materializes?

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

And it’s, again, the statewide expenditure, it’s total revenue requirement.

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

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

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

And what we’ve done here is to take these four different cases that we examined for going to 33 percent RPS and, you know, really, quite frankly I would say crudely and somewhat subjectively rated them on a pretty simple scale of kind of high, neutral, or low, or who are neutral in terms of their performance along a number of dimensions that have been articulated at various stages in time as important aspects at an RPS program, or things that we -- policy goals for the RPS program.

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

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

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

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

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

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

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

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

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

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

MS. RYAN: Well, I think the first one is that I don't anticipate, and Ann and Jaclyn can correct me if I say something really egregiously wrong. But it's not my understanding that will be doing additional studies on integration, but rather that we will be integrating into this analysis further study, most notably by the ISO, but anything else that we see that relates to both the costs -- you know, the costs, risks and timing associated with integration.

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

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

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

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

MR. ALVARADO: Okay.

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

MR. ALVARADO: Okay, I sort of bring it up just to lead into another workshop we're going to have on July 22nd, where we are -- the staff is engaged in an effort to update the levelized cost of generation estimates. And in this effort we're trying to come up with a band, a wider band of uncertainty variables to come up with a range of levelized costs.

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

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

MR. ALVARADO: Definitely.

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

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

MR. ALVARADO: I do think the high DG cases is pretty insightful and I do think there's probably numerous steps to try to make that reality. Is the PUC planning on engaging in any further analysis about what steps it will take to make this DG future a reality?

MS. RYAN: I'm getting nodding heads.

(Laughter.)

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

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

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

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

MR. ALVARADO: Okay.

MS. RYAN: I will mention, one of the things that we discussed among ourselves extensively, after reviewing earlier drafts of this report, is that DG analysis, the level of penetration that it contemplates is based on essentially a study of technical potential. You know, satellite mapping of rooftops, and spaces around substations and so on, and so forth, so trying to get a sense of just how many places are there to put panel.

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

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

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

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

MS. RYAN: Yes.

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

MS. RYAN: Right.

MR. ALVARADO: -- the generation totals.

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

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

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

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

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

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

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

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

COMMISSIONER BYRON: Right.

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

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

MS. RYAN: Right, uh-hum.

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

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

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

MS. RYAN: The all-gas case.

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

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

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

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

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

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

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

COMMISSIONER BYRON: Well, like I said, I think it's a good study, there’s a lot here.

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

(Laughter.)

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

COMMISSIONER BYRON: Are we losing you here, now?

MS. RYAN: You’re losing me unless somebody else has something to ask me.

MS. TEN HOPE: I have one question.

MS. RYAN: Okay.

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

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

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

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

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

Commissioner Levin, are you with us?

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

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

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

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

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

MR. HAWKINS: Good morning, Board and Commissioners.

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

But in addition to that, we're also doing work on cooperation with other balancing authorities, looking at the study that was mentioned earlier.

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

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

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

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

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

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

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

And again, using the expertise from the utilities, as well as other stakeholders to create a much more complete portfolios of what the wind, and solar, and different types of solar can do.

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

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

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

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

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

And so that one of the things to be done, of course, is to make sure that the data that you pick you end up -- as you escalate different years forward that you end up with a Saturday load profile that matches the generation Saturday load profile, and so forth as you build and synchronize these things for the future.

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

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

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

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

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

And so then, of course, what we have to do is to synthesize all these data into fairly comprehensive models, and then from that to make sure that we've got issues about inertia and everything else covered as part of doing our operating studies.

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

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

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

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

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

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

So that's basically our overall timeline.

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

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

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

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

MR. HAWKINS: Yes.

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

MR. HAWKINS: Well, one of the risks of course is that the capacity factors may not be totally realized. And so if you think you're going to get 37 percent from wind generation and it turns out to be 34 percent, you know, what is the margin that you're short and what else do you have to do?

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

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

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

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

MR. HAWKINS: Yes, we totally agree. The once-through cooling plant is certainly -- the expectation is that even plants that are going to be repowered probably will go off line for a period of time.

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

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

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

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

MR. HAWKINS: Yes.

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

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

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

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

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

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

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

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

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

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

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

MR. HAWKINS: That's going to certainly be a real challenge. Because in order to take the lines out of service to do the rebuild there certainly is a period of time -- you know, can you get the outages and how long will it take to do the rebuild?

Because often you're going to have to change the towers, as well as just the lines, so I don't know the details of that kind of a transmission issue, but that's a good question.

COMMISSIONER BYRON: Will your study get into that level of detail?

MR. HAWKINS: I assume that we would. That's something that a transmission plan would have to look at.

The other issue we discovered is that just getting the outages is no small feat, in order to take those kind of lengthy outages.

Yet, you know, as an analogy I guess, we did take a fairly extensive outage a couple of years go to do the replacement of the inverters on the big, high-voltage DC line, so that was done both at Bonneville and at L.A.

So it's possible to take these lines out and do these, so it's not like it's impossible.

COMMISSIONER BYRON: Well, I think you know we're counting on the ISO to figure out how to be able to do that.

But let me ask one last question, how are you addressing the non-ISO control areas in your study? Are you including them?

MR. HAWKINS: As far as I know, that from the operations perspective what we're trying to do is a region-wide study.

In terms of the transmission planning, I think Mr. Deshazo has been trying to include them as part of the overall RETI process and all that.

But in terms of the overall operations pieces, we've been mostly -- yeah, we've talked to, certainly with SMUD and planning with them.

We haven't had, I don't think, as much contact with L.A.

COMMISSIONER BYRON: Well, let me ask it differently then; are you limiting the results of your work to the ISO-controlled areas at this time?

MR. HAWKINS: Yes.

COMMISSIONER BYRON: Okay, thank you.

MR. ALVARADO: Okay, how about if we move along, we can open the panel up for public discussion in a while.

But next we have Ms. Tanghetti, with the Energy Commission staff.

MS. TANGHETTI: Good morning. I'm Angela Tanghetti, and I work in the Energy Commission's Electricity Analysis

Office.

And I want to share with you today some of the more interesting input assumptions and findings included in our recently posted Joint Renewables Office and Electricity Analysis Office staff report.

The staff in these two offices began this IEPR cycle trying to understand where the CEC could add value to any of the debate surrounding the 33 percent RPS Executive Order.

And our initial study was to focus on the type and timing of proxy generation that might be needed to back up or firm up different mixes of intermittent generation.

That is, would large amounts of wind development require different types of proxy generation additions, than similar quantities of wind development.

However, once we began our work to kind of quantify the input assumptions necessary for this type of analysis, the focus of where staff thought value could be added to this debate kind of evolved.

Once we realized the potential magnitude of all the scoping plans, electricity resource goals, taken together with a sample OTC compliance path, the focus of the study really evolved.

But first, when I mention the scoping plan, I'm referring to the Air Resources Board Climate Change Scoping Plan for the year 2020.

In this plan, goals for the electric generation sector are outlined, again for the year 2020. And 33 percent renewable energy standard is a key electric sector strategy in the scoping plan.

However, the other electric sector strategies contained in this scoping plan may have just as large an impact in the electric sector as 33 percent renewables.

So this is why we're attempting to study all the electric sector strategies outlined in the scoping plan.

Also considered again in this analysis is a sample OTC compliance path for some form of replacement or retirement of California's electric generators that use once-through cooling.

So again, our study evolved from the type and timing, understanding the type and timing of generation resources that may be needed to firm up or back up intermittents, to assessing the consequences of adding scoping plan resources and a sample OTC compliance path on the incremental amount of renewables, also known as net short, needed to achieve a 33 percent target, and also on the remaining system need for any capacity of energy.

We also tried -- we also assessed if there was a substantial difference between the performance of the existing natural gas-fired unit between a high solar or a high wind view of the 33 percent future.

And also, we looked at would improving the consistency of our load and wind hourly characterizations reduce any modeling uncertainty?

And could exogenous consideration, that is outside of any simulation model of local transmission and generation constraints yield useful information on the performance of any new natural gas-fired units.

So with these questions in mind, our office staff, with the help of the renewables office, developed three cases of the future WECC-wide generation development for the years 2012, 2016, and 2020 to test in some type of production cost model.

So let’s see, this is an interesting slide. So again, the focus years for the study are 2012, 2016, and 2020. However, for this comparison purposes, the values shown on this table here are only for 2020.

First, the assumption that’s common to all cases is this sample OTC compliance path, that last green column over there on the right.

And in it, you’ll notice that 12,655 megawatts were retired and about 7,700 megawatts are added back into the system.

So this 5,000 megawatts, basically the difference between the 12,000 and 7,000, are un-replaced generation, and that’s possible because of a combination of assumed transmission upgrades, and then there’s also generators that are located in areas with no local capacity requirements, or that generators, if retired, didn’t violate local capacity requirements.

The reference case considers only the sample OTC compliance path and a 20 percent RPS by 2012.

Also, for those not familiar with the term “net short” in this context, it refers to the amount of renewables needed to achieve the maximum RPS target, less the amount of any existing renewables.

So again, the net short in the 20 percent case is about 29,000 gigawatt hours. And then in the cases two and three, with the 33 percent renewables, it’s about 45,000 gigawatt hours.

Again, that’s in contrast to what the PUC findings showed as about 75,000 gigawatt hours of net short. So again, it’s a significant difference.

And what’s driving those are the complementary programs from the scoping plan. That is the complementary programs of energy efficiency and rooftop PV.

So when those complementary programs are combined, they can account for generation savings, as much as generation savings as a 33 percent renewable. So again, it’s an important consideration.

So this is basically just to outline the different assumptions and how they vary between the cases.

The next slide is just what I want to show here is the total generation, the total RPS generation by case that we looked at.

Again, the case one is again a 20 percent RPS by 2012 and, again, these values are for 2020. But what that equates to is, again, the total amount of renewables in that year is about 61,800 terawatts. And in this case the net short with -- again, was at 29,000

So what this is trying to show you here is the total RPS mix by case.

Again, the total RPS generation in cases two or three are the 78,000 terawatt hours, with a net short of about 45,000 terawatts in those cases.

The case one reference case reflects California’s current procurement path. So that is with the current -- the way the system’s currently being built out, you’re going to see mostly geothermal, with the remaining filled in, wind, solar, biomass, small hydro.

And even though we named cases two and three high wind and high solar case, geothermal and biomass fuels still played an important role in these 33 percent cases.

Let’s see, so the key drivers in this analysis are the study years are important, mainly for comparison purposes. For example, when we present amounts of non-renewable capacity additions for the year 2020, we're beginning from a base year of our study, which is 2012.

Our study assumes that no generation additions for the period prior to 2012 are already part of the existing generation and not new generation additions.

So just as an example, generation additions between the years 2009 to 2012 are forecasted to be about 5,000 megawatts.

Second, the amount of combined heat and power included in the scoping plan, staff assessed, is assumed to be all gas-fired and must take for this study.

A large portion of CHP host sites are located in Southern California.

Siting this level of gas-fired CHP might be difficult in light of the scarcity of emissions credits for this region.

And third, the sample OTC compliance path we used was predominantly combined cycles. More simple cycle additions may yield different results.

Another key driver in the study is the energy efficiency profiles. We had put hourly profiles in our simulation study and they were mainly targeting at lighting programs, with remaining savings from refrigeration and air conditioning programs.

Yes, we did model EE on the supply side in the simulation model. Since the scoping plan's goals for EE are above what was already included in the IEPR '07 demand forecast.

So this was one way to include a significant impact on natural gas use for electric generation in our simulation model.

But not only does EE impact electricity consumption, but based on this hourly profile of lighting programs, air conditioning and refrigeration, it does impact the peak demand as well.

So when you impact the peak demand either through this rooftop PV or EE, you impact the calculation of planning reserve margin and the need for any new generation.

Also for this study, Energy Commission staff developed a method to create internally consistent hourly load and wind shapes. And staff used the same algorithm to create both the hourly wind and hourly load shapes.

And this method uses actual wind generation and actual load data to create an internally consistent synthetic annual wind and load shapes.

So if you want more information about that, I'm not going to go into it now, but you can find the detail in our report, and I also added contact information at the end of this presentation.

So what's interesting as far as -- this amount. This

1,910 megawatts of new generation additions between 2012 and 2020. We think that's interesting because 1,900 megawatts of generic, non-renewable generation addition was added to the reference case between those two years in order to meet a -- we did a 15 percent planning reserve margin by control area. So we didn't do it statewide, we did it by control area, and the control areas for California, the ISO, L.A., SMUD, TID and IRD.

So what what was our criteria for adding new, nonrenewable generation?

For the reference case, case one, renewables are added in each study year to meet a 20 percent RPS target.

Staff did develop a sample OTC compliance pack that considers transmission upgrades, local capacity requirements, and a really simplified consideration of inertia requirements in Southern California.

And so for each control area in California and actually the rest of the WECC, a 15 percent planning reserve margin is enforced by either -- by adding either proxy simply cycle or a combined cycle generation.

Again, a common thread to all three cases is the sample OTC compliance path and a 15 percent planning reserve margin.

For cases two and three, resource planning development, renewables added were added in each year that phased up for the 33 percent by 2020.

Also phased in were the scoping plan goals for combined heat and power, and this equates to about 4,500 megawatts of dependable capacity by the year 2020, just for the combined heat and power goal.

For the scoping plan energy efficiency, that was also phased into the year 2020 and this equates to about 6,000 megawatts of peak reduction, if you're looking at the hourly profile we used for that.

And again, resource plan development is done exogenously to any simulation tool, so we just make these calculations before we do any simulations.

So once we do input all these resource plan assumptions, once we build those into our simulation tool what can we find that's interesting?

And in the past, one of the first simulation results we always examine are capacity factors. So specifically we wanted to look at the capacity factors of the once-through cooling additions, since we thought these were of interest, because they're one of the few dispatch able resources we have in the simulation tool for California.

For the reference case, the OTC replacement capacity factors are what we considered to be, today, in an expected range.

The capacity factor is shown for the combined cycles in cases two and three, again with the higher penetration of renewables and other scoping plan goals trend much lower.

What’s the right capacity factor for combined cycle in the future?

Based on research and gut feeling, 60 percent seems plausible.

However, we have historically seen some capacity factors in the 20 to 40 percent range and those units are still in operation today.

So are these capacity factors too low? More than likely if one assumes the generation owners are finding revenue only in the energy market, and this may not be the case by the year 2020.

And again, this is where we think an area of further sensitivities is needed.

We did complete some simple sensitivities, where we kept the total amount of once-through cooling replacement the same, just changed the ratio of the simple cycles to the combined cycles, and the capacity factors did approved for the year 2020 for cases two and three. However, only by about ten to 20 percent so, correspondently, a simple cycle capacity factor is dropped as well.

So again, we think this is an area where further sensitivities are warranted.

Let’s see. Okay, the interesting bar in this chart is again this dark green one here. So I know your eyes may want to go to the purple bar, but the darker green bar is where I really intend you to focus.

The darker green bars are simulation results for the year 2020 for dispatchable natural gas-fired generation in California. While the lighter green, those lighter green bars right there are generation from the must-take gas-fired combined heat and power.

And then the purple top bar represents that EE savings, that was modeled as part of the resource mix in the year 2020 so, again, that dark purple is energy efficiency.

This is the combined heat and power and, again, these were the differences in the dispatchable gas, and these are case one and case two, high solar, and case three high wind.

For many hours, in any given year, the resources in our simulation tool has available to load follow is natural gas-fired non-QF generation.

I'm not saying that all hours of the year, but definitely the majority of the hours in a typical year, the marginal generator is gas-fired.

So that's just what this chart's intended to demonstrate.

Natural gas use for electric generation in the year 2020. Again, for this analysis the high wind case uses slightly more natural gas in California that the high solar case. This appears to be intermittency-driven results. More units in California are committed and a few more dispatched under the high wind case.

Since more generators are committed and dispatched in California, slightly less natural gas-fired generation is needed as imports coming into California.

But note that these differences for case two and three are pretty insignificant with respect to overall gas-fired generation in California.

However, the higher penetration of EE, rooftop PE and renewables for cases two and three do impact the natural gas use for generation when compared to the reference case, not including those complementary programs and meeting the 20 percent renewable target.

Let’s see, this chart is just intended to show you how natural gas-fired generation does increase over the forecast years, no matter what case you’re using. The growth is definitely more modest from 2012 to 2020 for cases two and three but, nonetheless, this is just to show that natural gas use is increasing over the forecast years no matter what case you’re using.

Let’s see, so the next step. Over-generation issues. And there are possible instances of over-generation in our simulation results. And over-generation, how we’re defining it, is a condition where more generation is provided than load is available to consume it.

The way we intend to quantify this is using a production cost model and on an hourly basis trying to quantify any of your baseload must-take resources are running at lower than their possible generation in that hour.

And also what we intend to look at, as Mark Minick pointed out this morning, is to quantify the stops and starts of your pump storage units as well.

The scoping plan does include goals for electrification of the transportation sector. Staff here needs to explore better the type and timing of these proposed goals to better understand how these transportation sector goals could impact the electric sector in the 2012 to 2020 time period.

Some contend that the impact may be small in our demand forecast, but depending on the type of electrification.

Again, some sensitivities. We'd like to look at simulation results for different OTC compliance paths, one with more simple cycle additions in contrast to the current sample OTC compliance path, where we definitely choose more combined cycles.

Nonetheless, many of the OTC plants that are poised for retirement must be replaced with local generation and transmission reliability purposes.

Should we characterize CHP differently? Maybe lower the amount, recalculate the amounts of renewables needed to meet RPS net short if that’s the case.

We’d like to incorporate the 2009 IEPR draft demand forecast, the impact on the amount of new renewables and, ultimately, natural gas used for electric generation.

And based on other IPO work, we may want to adjust the hourly profile for EE. Also, when we do incorporate the 2009 IEPR forecast, we need to ensure that any EE from the scoping plan is now not double counted in our demand forecast, as well as rooftop PV.

So those are some of the next steps and sensitivities we’d like to do for this analysis.

And also, again, it was a joint Renewables Office/Electricity Analysis Office report. So if you do have questions on the renewable portfolios, again, I’ve tried to provide some contact information here. And also, the report can be found at that URL, if you haven’t yet looked at the report yet. Okay.

MR. ALVARADO: Thank you, Angela. I do think that some of the assumptions that Energy Commission staff did include in this study are somewhat different from some of the other studies that we’ve found from the ISO, the utilities, and the PUC, so I do think it does suggest that further, additional studies or investigations are needed, working together with the other parties.

I really don't have any questions but, Commissioner, do you have any questions for Ms. Tanghetti?

COMMISSIONER BYRON: Ms. Tanghetti, just a couple of quick questions. Obviously, on net short, assuming the Energy Commission's analysis is a lot less than the others that we've seen today, and I assume that's based on a revised forecast they didn't have access to?

MS. TANGHETTI: The differences mainly in the net short are, again, a revised forecast of existing generation. I noticed in the PUC report it was about 27 terawatts. What we assumed for existing renewables by the end of 2008 is about 32.5 terawatt hours, so that's 5,000 terawatt hours difference, which is a large amount.

And some of that could be attributed to we include the POUs, out-of-state renewables as existing as they are now. So again, the starting point is different, you're correct.

And inclusion of the complementary programs, when you include significant amounts of EE, rooftop PV, and combined heat and power that lessens your amount of retail sales. And so the RPS is calculated based on retail sales, so that has a significant impact in that calculation.

COMMISSIONER BYRON: Right. Well, I don't expect an answer, but I think the question on everybody else's mind is what if we're wrong?

One other quick question and then I think Ms. ten Hope has one.

I noticed as well from our work that not much -- there’s not much natural gas usage reduction as we go through the years and, therefore, there’s not much GHG reduction either from the renewable cases; correct?

MS. TANGHETTI: Correct.

COMMISSIONER BYRON: And as you indicated, natural gas use will continue to rise over the years regardless of what scenario you’re looking at.

So where’s the tradeoff. What’s the benefit of moving to renewables if we don’t reduce GHG?

MS. TANGHETTI: Diversify your portfolio. But again, it’s all driven a lot by our assumptions of energy efficiency which, again, lessens your amount of renewables that you’re adding to the system.

So it’s kind of a tradeoff there. Another assumption is that the combined heat and power outlined in the scoping plan, we’re assuming that to be all natural gas. There are options for lessening natural gas use in there.

So if you do increase the amount of renewables and assume that less of a combined heat and power is gas-fired, again you’re going to be maybe on a flatter growth of natural gas demand but, nonetheless, not as much of an increase as you see in just the 20 percent case.

So it does have an impact if you look at those overall charts on gas use.

COMMISSIONER BYRON: Thank you.

MS. TANGHETTI: Sure.

MS. TEN HOPE: I just wondered, this current net short use is the ’07 load forecast; is that correct?

MS. TANGHETTI: Correct.

MS. TEN HOPE: So we would expect this to go down to the more updated for ’09?

MS. TANGHETTI: It depends on the ratio of the additional EE in the new demand forecast. It looks like there is a significant portion, as you get out in the future, is economic driven, but a portion of it is also energy-efficiency driven. So we might not be lowering our amount of renewables net short by as much as one would think. We don’t want to double count those.

MS. TEN HOPE: And then I think you said one of the big differences between this net short and the PUC study was the assumptions about energy efficiency and meeting the energy efficiency targets in AB 32.

I thought that the PUC study included aggressive energy efficiency, but maybe it’s the current energy efficiency goals of the PUC and not full achievement of AB 32.

Can you clarify which energy -- I mean, what the difference was in the energy efficiency assumptions in the two?

MS. TANGHETTI: I don't think I can. Can you, Jaclyn?

MS. MARKS: I don't have the numbers off the top of my head, but in the base case we assumed the mid-level goals, which was in the 2007 IEPR forecast.

And for the low-load sensitivity, we assumed full achievement of the AB 32, energy efficiency and other demand cycles.

MS. TEN HOPE: Okay.

COMMISSIONER BYRON: Thank you.

MS. TEN HOPE: It's still a little bit mysterious what the big difference is, though.

MR. ALVARADO: Given the time, maybe we can move forward to Mr. Brand. I do know Mr. Brand has a full, extensive set of slides that was also included in our website, too, that has the details of the city assumptions and results.

MR. BRAND: Thank you. I was going to say good morning, according to my notes, but I'll say good afternoon, instead.

My name's Geoffrey Brand, I'm with the Gas Market Modeling Group, with ICF International.

Two other principal, key members of our team are Kevin Petak and Frank Brock, and their contact information is on the slide.

Our study is a little different. We're not looking at the electricity network, we're actually looking at the natural gas network in California and see how renewable generations would have an impact on that.

That does not look good. More specifically, we're looking at how variations in renewable power, mainly wind and solar, will affect gas generation and, therefore, gas consumption in the power sector.

Our goal was essentially to project the adequacy of California's natural gas pipeline infrastructure, the gas pipelines and gas storage in 2020 to meet a peak day requirement.

The natural gas system in California peaks in the winter, so looking at a January peak date in 2020, the year that the 33 percent renewable RPS standard will be met.

To do that, ICF modeled not only California's natural gas infrastructure, but pretty much the entire western U.S. We did this in five different scenarios.

The different scenarios, we have a base case, but the scenarios also varied weather conditions mainly, specifically, temperature. On a more adverse weather day we have colder temperatures and have higher natural gas utilization, and higher electricity sales amounts.

We also varied the amount of type of renewables mix, what proportions of solar, wind, biogas generations, and we also varied the amount of solar and wind generation available.

For instance, if the wind is not blowing quite as hard or solar, the sun is not shining as much, essentially we would have less -- less generation available and, therefore, higher gas generation necessary.

The assumptions we had were actually based on scenarios we had with the Implementation Analysis Working Group, and we took those assumptions of generation mix of the various renewables.

We used CEC’s 2007 projection for electricity demand growth, and that is about 1.1 percent a year to 2020.

All other natural gas assumptions are based on our own internal base case. They have the assumptions of what the other sectors, other than the natural gas market are doing, space heating for residential and commercial load, and any industrial gas demand.

Our natural gas pipeline and storage infrastructure are also based on our internal forecast.

Inside California we do not have any large amounts of -- we have no pipeline capacity additions assumed by 2020.

We do have additional pipelines going to the border, but nothing within California.

We also assume storage, natural gas storage additions of two additional natural gas storage fields and one storage field expansion.

But in general we're using pretty much the same natural gas infrastructure we have today.

These are our five cases. We have a reference case which kind of has the -- we meet the 33 RPS in 2020; we have the expected generation from those renewable assets; and then we assume normal weather.

I think I missed, for a peak day this would be in January.

Our second case we just look at adverse weather, and essentially we have a much colder day in January which increases both natural gas consumption and electricity sales, and we also have more adverse hydro conditions in the Pacific Northwest, which reduces electricity imports from there due to lower generation in the northwest.

Case three, then we assume lower solar and wind generation due to less favorable conditions at the generation sites and then we compensate that by increasing gas demand.

And then case four and five are similar to three, but we have a different generation mix. In case four we have more wind generation assets and in case five we have more solar assets.

I'm not going to spend too much on this slide, but this kind of shows the modeling process we did to reach our peak day requirements, that was our final goal.

We have like a variety of models. GMM stands for gas market model. Essentially what that does is model the entire North American market on a monthly basis, pretty much out to 2030.

That is kind of necessary because gas supply and demand and regional flow throughout North America impact how much gas is available for California.

We take that monthly model and then that sets beginning and ending month conditions for our daily model. Our daily model shows daily gas demands and regional flows for an individual month.

And then finally we take those daily and monthly results and we put them in what we call RIAMS. RIAMS stands for Regional Infrastructure Assessment Model.

And what that is, is actually a more detailed infrastructure model just in a specific region. In this case it was the Western United States.

The level of detail is actually county by county, and so we have pipeline capacity going between counties and we also have individual large assets, such as storage fields.

So our level of detail for the study was on a county-by-county basis and a daily type from a time period.

This graph table shows our projected assumed electricity generation for the reference case, actually for all cases.

As you can see, if you look at the 2008 column, we have 268 terawatt hours of retail electricity sales. We have 39 terawatt hours of renewables of both internally generated and imported, which equates to about 15 percent of that total electricity retail sales.

If we go according with the 2007, 1.1 percent down to about 300 -- I’m having a hard time reading that -- 309 terawatt hours by 2020, then we have 103 terawatt hours necessary renewable sales to meet that 33 RPS standard.

An important part to look at this slide, look at the very top line as in gas generation, you have gas generation roughly around 120 terawatt hours in 2007 to 2008. If increasing renewable generation, you only can get around 90 terawatt hours by 2020, so we see a reduction in the amount of electricity generated from gas-fired units.

The top table up here shows the various generation mix of the various renewables by renewable source. For the reference high, we have a high wind case and then a high solar case. Each meet the 103 terawatt hours by 2020.

The table below shows how we reduced it when we had unfavorable conditions for generation.

Wind generation, we looked at the reduction of 24 percent, which is not showing up at all, sorry about that.

But that was mainly based -- it was sort of the reduction of potentially 24 percent below was based on 30 years of weather station data. So if we took the low wind year in the last 30 years, we could possibly see a reduction of 24 percent of what we'd expect to if we had a normal year, and then the solar generation with a reduction of nine percent.

This graph just kind of shows wind variability within the projected month of January for the reference case, from the 31 days. This is actually sorted lowest to highest, in essence because it can certainly go up and down during the month.

But given normal weather patterns we can see lows, just because different days have different outputs, of roughly 30 gigawatt hours per day up to 150.

On the reduced generation case, we assumed that those amounts were reduced by roughly a fourth.

And for our stress case for this system, we were trying to model the natural gas infrastructure, we assumed that the coldest day appeared on the lowest wind generation day, so it would be the worst case scenario.

In this slide, and this kind of shows the California balance for an average annual day. The big key points here is that in 2008 California consumed an average of about 6.3 billion cubic feet per day, and by 2020 that is going down to about 5.4

So in essence we are projecting a decline in natural gas consumption for the State of California given these assumptions.

The biggest drop was actually in power generation, it actually dropped about .8, or the .9 VCFD drop.

The other sectors, residential, commercial and industrial are essentially pretty well flat.

On the supply side, gas production, internal California gas production's roughly the same. Therefore, that drop was due to -- was balanced by reduced pipeline imports.

This is what our assumptions are, what our projected analysis came up with for gas consumption on a peak day, given normal weather. This is about 8.2 billion cubic feet per day. The average day was 5.3 in 2020. So on a peak day, the highest day of the year, you'll get about 50 percent extra load.

The half of that load is space heating in residential and commercial sectors, while 30 percent is the power sector and about 20 percent is the industrial.

I apologize for the lack of clarity on the slides. They look a lot clearer on my computer.

This is showing a map of how the peak day is actually met. The large arrows going into the State are pipeline flows and imports. The number off the top, if you can see, I don't know if you can see that, but it says roughly 1.2

Bcf a day of pipeline imports up in Malin, Oregon, the northern border there. But there’s about 2.2 Bcfd of capacity. So there’s a fair amount of capacity available left, even on a peak.

Again, roughly, you have down below 2 Bcdf capacity on the Arizona border, and about 4.9 Bcdf capacity.

Of course, we not only modeled import sites, we modeled pipeline capacities throughout the State of California and it was adequate to meet the reference case results.

Storage was actually -- was draws. I think about 3.6 Bcdf, ’m having a hard time reading it myself, but that’s just about a little over -- a little over the 6.5 billion cubic feet per day of projected storage capacity. So there’s a fair amount of additional capacity for reliability purposes, even on a peak day.

These are results of the other cases. Case two is just the adverse weather, if you have a much colder day than your typical, average January cold day, you will see additional 1.1 billion cubic feet per day.

The reduced renewable generation of both wind and solar for all the cases range a little bit, but they’re roughly the same, and they kind of peak at an additional half a billion cubic feet per day. So you end up with roughly around 9.8 cubic feet per day. Which is not terribly different than what we have right now.

And these are just a quick summary of my results. A 33 RPS standard leads to a decline in gas demand in California, even under assumptions of adverse weather and hydroelectric conditions, we might consume on an average year less than what we're consuming in 2008.

Reduced renewable generation's not significant enough to cause potential problems with the current pipeline structure, even with that increased half a billion cubic feet per day due to reduced renewable generation.

And then the final point is technology mix, especially such base loads of supplies, such as geothermal, really help the -- reduce the variability of potential need for gas-fired generation.

And also, if you geographically move the wind generation and therefore you have a much more steadier, such that you don't have wind dying all in one place, therefore a geographical mix of both the solar and wind will also help on keeping the assumption more steady.

And finally, some caveats. This was based on the 2007 CEC projection of 1.1 percent growth per year in California electricity load. I know there's a newer update, but if that changes, that would change the results of the study.

Our wind and solar variability was some estimates that we came up with. Obviously, there's some more, could be much more better detailed as more specific sites are decided upon.

This analysis also assumes that when renewable generation was not being -- was reduced, that was essentially made up with gas generation essentially in the same spot. That might not necessarily be the case.

And finally, our granularity of our study was based on county level assessment. There may be more local bottlenecks that we’re not covering.

And also, we only looked at it on a daily basis. Certainly, there might be some hourly problems that might come into affect.

And that is all I have, thank you.

MR. ALVARADO: Thank you, Mr. Brand.

I guess the general uptake I see is that the natural gas system is really going to be adequate. I had some questions more about the day-to-day variability, you know, if you do have a high wind case, and one day last week the wind was blowing really strong, it was a lot cooler, and then next day suddenly the wind -- a high pressure front comes in and the wind just stops.

Is the gas system, do you think the gas system really is going to be adequate enough to be able to take that just immediate surge need for gas generation?

MR. BRAND: Well, I think the biggest stress on the system will actually be on a cold January day. So if that happens in the midst of January, that’s most important. If it happens on a shoulder month, the pipelines can be fairly, you know, well packed with line pack and cover a lot of that.

So again, it’s more of a -- if it comes to extremes it’s local problems, but as a system as a whole it will probably be fine.

MR. ALVARADO: Given that some of the other scenario analysis, like the one that Angela has put together, does have sort of a different gas demand trajectory, then is there in your analysis, are you considering a point where the gas system really does become stressed?

MR. BRAND: Well, certainly, if you had a 1.1 percent growth in renewable generation -- I mean, electricity sales, I mean if that does not come to pass, we’ll actually make this system worse.

Also, we have very flat residential/commercial demand. We’re assuming that there are strong efficiency programs to essentially keep that demand flat, but might have population growth. Therefore, the other sectors, not the power generation sector, might grow and cause a number of problems.

So there’s certainly uncertainties in not only the power generation, but the other sectors.

MR. ALVARADO: Thank you.

Commissioner, do you have any questions?

COMMISSIONER BYRON: I do. Thank you, Dr. Brand.

It looks as though your study is a little bit different than the Energy Commission with regard to how much less natural gas would be used with a full build out to 33 percent renewables.

In fact, if I'm understanding figure six correctly, you show natural gas for power consumption in 2008 at about 121, I assume that's billion cubic feet. Anyhow, the relative number is 121 to 90 in 2020. I'm looking at figure six.

MR. BRAND: Gotcha.

COMMISSIONER BYRON: So that's about a 25 percent reduction, I think. I don't think we saw numbers nearly that large in reduced gas usage. Am I doing my math correctly?

MR. BRAND: Yeah, that is correct. Essentially, that's driven by the assumption of electricity sales of getting the 103. That number was kind of fixed based on we're trying to meet the 33 percent standard.

And then the electricity sales of 309, which is -- that was a growth from -- of 1.1 percent per year.

The other large hydro, the nuclear renewal, they don't really change all that much. The gas-fired generation just dropped out of the numbers that we have.

So if there's uncertainty on the electricity sales or the uncertainty of the -- let's see what else it would be? Well, again, the 33 percent standard is kind of fixed, also.

COMMISSIONER BYRON: I didn't go back and look at the Energy Commission reduction. Ms. Tanghetti, do you have any comments as to why they're so different in the natural gas drop off?

MS. TANGHETTI: First off, we didn't run the simulation for 2008, so I don't have any comparable data for that.

But again, what we assumed was that there were far fewer renewables added to the system and also, by 2012, there wasn't that amount of energy efficiency as well, so our numbers differed there.

But then also another area that where we're seeing demand grow in the natural gas sector is we assume combined heat and power is all going to be fueled by natural gas. So again, that's one of the driving results for that as well, again as not the amount of renewables added to the system that they assumed in their study.

Also, if the number was 308 that you put in for sales, it's really an electric model, it should really be the net energy for load, which includes a significant portion for transmission losses, so you have to generate for those as well, so that could impact it as well, too.

MR. BRAND: Well, actually, we had that energy below the 353. I apologize, you probably couldn't read it on the poor resolution of the table.

MS. TANGHETTI: Okay, good.

MR. BRAND: But the combined heat and power assumption, if there was more combined heat and power, which are not part of electricity sales, then our renewable number of 103 terawatt hours would be able to be lower, then we would have higher gas-fired generation.

MS. TANGHETTI: As well as energy efficiency?

MR. BRAND: Yeah, right.

MS. TANGHETTI: So those assumptions do drive some of the gas use.

Again, the gas use it not -- I don’t think it’s that different. Again, if you look to 2012 and we start comparing the numbers, I don’t think we’re going to see as significant of a difference. But again, our numbers are going to be higher mainly because we didn’t add as many renewables and that we did include combined heat and power, natural gas-fired.

COMMISSIONER BYRON: Thank you, that’s a good discussion. Any other questions?

Ms. ten Hope?

MS. TEN HOPE: I just had one question. On your slide 13, you say that the results would differ based on geographic diversity and renewables. Did you assume that the renewables were built out evenly across the State or --

MR. BRAND: No, solar we had all in the southern part of the State. And wind, I think we had more of it spread out. But it was kind of more looking at where the sites were.

MS. TEN HOPE: Okay, that's the basis of my question, because we presume that most of it will be in Southern California.

MR. KINOSIAN: Yeah, actually one question just following up on one of the earlier questions.

The Energy Commission assumed 4,500 megawatts of new combined heat and power projects. Did you assume any additional heat and power projects in looking at the gas usage?

MR. BRAND: I think we have some, but it really won't matter on gas consumption whether -- there might be some minor locational issues.

But if it's gas-fired generation, where it's combined heat and power, I don't feel that the efficiency differences of heat rate would matter that much, you still have that same amount of -- what it would do is break down that amount of renewables necessary to meet the 33 percent standard.

MR. ALVARADO: Well, we are spilling into the targeted lunch hour, but I did want to give the panelists an opportunity to field any questions from the public, or anyone else that might be on our WebEx. So if there's anyone --

MS. KOROSEC: We do have one question on the WebEx, for the PUC staff, from Arthur O'Donnell, from Center for Resource Solutions. Arthur, you're line's open.

MR. O'DONNELL: Hi, can you hear me?

MS. KOROSEC: Yes, we can.

MR. O'DONNELL: I wanted to ask Nancy Ryan, but she's gone, so if the others could answer, please. In the absence of any analysis, if we used tradable renewable energy certificates to meet the 33 percent, that seems to presuppose an extreme policy decision that's not yet been made and it could lead to higher costs in what transmission constraints in this analysis.

Also, it seems that this report puts all reliability resources in the State rather than using western interconnected markets to supply them.

Why were those options neglected and what might you think the changes would be if they were included?

MS. MARKS: Hi, this is Jaclyn Marks and I'll answer your questions.

We did not model WECC because our cases were based on existing policy and right now WECCs are not allowed to be traded.

And as you know, the PUC put out a proposed decision on this. But it is a hot issue in the Legislature and the

Legislature is considering this issue for the 33 percent RPS legislation.

So as a result, you know, we don’t know what the outcome will be and we’ll wait to make a decision on how to model that once there’s more clarity.

MR. O’DONNELL: Okay, but Nancy’s position was that you really weren’t going to be doing further analysis and the compromise with the Legislature right now is to allow for 20 percent, so you might miss the boat.

MS. MARKS: We are not going to do more analysis for this study, but that doesn’t mean we won’t do more analysis in the future because I think WECCs could lower the cost, as you said, of the total program.

But as for the transmission, you know, renewable energy in other states could have transmission constraints, so that’s another thing we need to consider.

As for your other question, our renewable integration analysis was very high level and it was based on the CPCU/Energy Commission join decision on climate -- AB 32 and the greenhouse gas analysis.

And I’m not sure exactly if there were location assumptions or not. I know there were very high level cost assumptions.

And we’re going to rely on the California ISO for more detailed analysis on this. So I think Dave Hawkins is the best person to ask for more clarity.

MR. O'DONNELL: Thank you so much.

MS. KOROSEC: And we have no other questions on WebEx.

MR. ELLIS: This is Jack Ellis, I've got one question for David Hawkins.

In the study you're about to do, you looked at or considered examining the impact of pushing the existing fleet and generate -- thermal generation to be built harder than is advertised. I've been told that some of the existing generators say that they could do more, that they could move faster if the compensation scheme were right.

MR. HAWKINS: Yeah. Excuse me. Yes, that's correct, we've had discussions with generation owners as to what it would take to do higher ramp rates and move the units harder. And those have been insightful.

And again, the issue comes down to a compensation issue. If we're going to move and stress the generators more, what is that compensation for being more aggressive and how do they cover their additional maintenance costs, so those are sort of ongoing discussions.

MR. ELLIS: Okay, and then a question for Ms. Tanghetti. Did you, in your study did you look at all at the impact of alternatives to gas-fired generation for load following and ramping?

MS. TANGHETTI: No, we just put that in as a proxy.

We're not trying to determine what's going to be there in 2020, we just had some kind of a proxy.

We did choose between a simple cycle or a combined cycle, trying to determine whether it was more of a capacity need or energy need in the future.

MR. ELLIS: Okay, so at this point you don't know whether alternatives to gas-fired generation, period, might have some impact on GHG emissions and natural gas use?

MS. TANGHETTI: No, it's just a proxy that needs to be there.

MR. ELLIS: Okay, thank you.

MR. MAGALETTI: Mike Magaletti, with the Energy Commission.

Angela, I was interested in the difference in the natural gas consumption between your study and our study on not looking at the electrical system, but looking at the natural gas system.

And the one thing that you two were saying earlier about the CHP got me to thinking, you had almost 8,000 megawatts of CHP at what capacity factor?

MS. TANGHETTI: I'm not sure exactly what capacity factor, and it wasn't 8,000 megawatts, it was about 4,500 megawatts, still not insignificant.

But again, it's whether you include that on the power gen side or whether you include it in the industrial side, so I don’t think we’re exactly -

MR. MAGALETTI: That was the next question I had, how did you assign the gas -- the fuel for that CHP; did it go to the power gen side or did it go to the industrial side?

MS. TANGHETTI: We modeled it at a reduced heat rate, so that part of the gas use was going for the process and part of it was going for the portion that was providing power to the grid. So we tried to take that into account and only count the amount of gas use that was providing power to the grid.

So again, it could show up on either side of the equation.

MR. MAGALETTI: But did the total -- and apologize for not being as familiar with your study. Did the total gas use for both the electricity generation in CHP and the thermal, did that get factored into your assumption regarding increase in gas demand over time?

MS. TANGHETTI: Yes.

MR. MAGALETTI: Okay. So I think when you say, Geoff, that CHP doesn’t matter, I think it matters in total gas demand.

MR. BRAND: Yes.

MR. MAGALETTI: But you’re actually right, in electrical generation there’s less of a -- you’d have to run it, it’s a more granule analysis, I suspect.

MR. BRAND: I think the big thing was the fact that the amount of necessary renewable generation to meet the 33 percent standard is so much lower because electricity sales are lower because it's not counted, that's where the big change is.

MR. MAGALETTI: And that --

MR. BRAND: Actually, when I say it didn't matter, I mean to say from, one, you know, the amount of electricity generated to meet whatever demand in the future is for CHP or a normal generator, you know, the heat rates are not going to be terribly different, it wouldn't matter too much in the total amount of generation.

MR. MAGALETTI: But you'd have less renewable generation to back off your natural gas?

MR. BRAND: Yes, the natural gas, where the big change in gas consumption comes from was the portfolio mix of generation assets.

MR. MAGALETTI: Okay, thank you.

MR. ALVAREZ: Antonio Alvarez, from PG&E, just have a couple of questions on the ICF study.

I think you mentioned your own account for the intra-day uncertainty, with respect to wind or solar generation; right?

MR. BRAND: Yes.

MR. ALVAREZ: And also, the 24 percent, is that 24 percent decrease assigned to the peak day as a function of whatever winter wind or solar generation is expected?

MR. BRAND: What we did is essentially took our estimate for wind generation for 31 days, and took every day, and not -- reduced it by 25 percent, or 24 percent.

And actually, we did look at it seasonally, so January was actually 25 percent versus an annual average of 24 percent. So that -- so therefore, we assumed the peak day occurred on the lowest wind generation day, so it was kind of the worst case scenario.

MR. ALVAREZ: Okay. One other question that I had, and perhaps a suggestion to look at the summer, given the summer injection season, and the additional storage that you're including. Summer for us, I think given the electric peak occurring in the summer will be probably a more stressful time, as well as the fact that we have -- perhaps in the spring we have most of the wind generation and, you know, summer solar generation.

And so looking at the variation, particularly with the day-ahead forecasts in both of those resources, coupled with the additional injections for the summer, when people are starting to load up for the winter, might be a good thing to look into.

MR. BRAND: An additional study, yes.

MR. ALVAREZ: Right. And I do have a couple of questions on the Energy Commission study.

Again, my assumption in reading the study is that day-ahead uncertainty, hour-ahead uncertainty were not included in the simulations?

MS. TANGHETTI: The model does an adequate job of doing the day-head, but the hourly, intra-hourly that another simulation model captures is not.

But the day-ahead, it does a fairly good accounting of that.

MR. ALVAREZ: So it accounts for the uncertainty in the load forecast in --

MS. TANGHETTI: No, it’s a determinate, we didn’t run it in --

MR. ALVAREZ: Oh, so it’s deterministic, okay.

MS. TANGHETTI: Yes.

MR. ALVAREZ: And what assumption was made about the combined heat and power, was it assumed -- I get the impression that there were some losses added to the savings. Is the assumption that all the combined heat and power is added at the customer side of the meter?

MS. TANGHETTI: I’m not sure exactly what side of the meter it’s included, but we did include transmission losses. The scoping plan goals was about 30,000 gigawatt hours that they wanted in savings, and then we simulated about 32,000 so we tried to capture the losses associated with that.

MR. ALVAREZ: So that implies that it would be small combined heat and power gain added, as opposed to a large, export combined heat and power?

MS. TANGHETTI: We didn’t really make any specific assumptions about small. The way our model works is we can just plot different amounts in different regions in California, and so we just assumed that in total they were about 4,500 megawatts. Exactly what they were is not real clear.

MR. ALVAREZ: Okay, thank you.

And I have one last question for the Public Utilities Commission. There is a slide, and I’m sorry to get into the weeds, but when we look at the gas price sensitivity, we do see a reduction in the downside in terms of, you know, when gas prices are lower, the savings associated with a lower gas price scenario is not there, which is expected. But also, when the gas price goes up, somehow the total cost also increases, which is surprising to me. I would expect that the RPS generation would provide some page value. And I’m not seeing -- this is slide 16.

MS. MARKS: Antonio, we agree with you and we were surprised, too. And that was one of the findings of this analysis is that the 33 percent RPS provides a hedge, you know, as you can see from that slide, it decreases the range of volatility.

But in terms of the high end of the prices, you know, it doesn't decrease prices that much. So it was a surprising finding and something that could require more analysis and something to look into further.

MR. ALVARADO: Any other questions?

COMMISSIONER BYRON: Thank you, Mr. Alvarado. Thank you, Panelists, very much.

I think it's time for a lunch break. Let's reconvene, by the clock in the back of the room, at 1:40.

(Whereupon, the luncheon recess was taken at 12:40 p.m.)

--oOo--

AFTERNOON SESSION

MS. KOROSEC: 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 legislation.

I guess my overarching thoughts, sort of in response to all the questions, is that from the number of the conversations that I heard in the course of the morning, there seems to be a need for some general, low-carbon grid planning. And this would be a planning effort that would encompass all the various stakeholders, the various regulatory agencies, the ISO, the utilities, and focus sort of what we have now for low-carbon grid technologies, different renewable technologies, as well as demand response storage, as well as other complementary infrastructure technologies.

Look at what we have now and look at how all that fits together and just try to think about ways to look at the system more holistically and sort of incorporate all the different climate and the energy goals that we have all at once, and I think this will help with some of the long-term planning concerns that we have.

In response to the first question, just on electricity integration and integrating variable amounts of renewable energy, I want to call everyone's attention to a study that came out by the North American Electricity Reliability Corporation this spring, earlier this spring.

This report had a number of important findings that could be useful to both the CEC, the ISO, and the PUC in terms of integrating variable renewable resources.

Specifically, I'll go through a couple of those findings. First, it noted that wind plants are already an important contributor to grid reliability. And their performance capabilities now equal or exceed that of traditional power plants.

They also found that the policies that govern how transmission lines are planned, paid for, and permitted need to be updated so that transmission can be built to connect to new wind projects. And that's a thing that definitely we're all familiar with.

Also they found that while wind power can be characterized by variability and uncertainty, grid operators already constantly accommodate variability and uncertainty while dealing with changes in electricity demand and unexpected outages of traditional power plants.

They also found that the reliability standards must be fair, transparent, and performance based.

So these findings led them to a number of suggested reforms, including the consolidation and cooperation of the small, balkanized grid operating regions to form larger operating areas. And that may offer significant reliability and economic benefits.

It also found that the wind forecasting should be expanded and wind forecasting should be integrated into power system operations.

Power plant scheduling and dispatch should be conducted for shorter intervals than is commonly done today, somewhere like five or ten minutes, rather than hourly, and this will greatly enhance grid flexibility.

Also, the flexibility of the grid can be enhanced by adding new types of generation and demand response resources, and by creating markets to incentivize this flexibility.

In terms of some of the policies in the scoping plan, I think that certainly the goals outlined in the scoping plan will help California reach its greenhouse gas goals. And we heard that pretty clearly from the CEC’s presentation this morning, when she discussed the interplay between energy efficiency and -- energy efficiency achievement and renewable energy procurement.

The CEC study highlights the need to analyze and plan for the interactions among the State’s various policy goals.

I think this also highlights the need for better portfolio-based planning, as I mentioned earlier, on behalf of the load-serving entities to ensure that they’re meeting their greenhouse gas targets and complying with other regulations more effectively.

Additionally, I just want to highlight that the scoping plan does mention a few supporting policies in the 33 percent RPS section, including transmission planning, as well as expansion of California's current feed-in tariff program. And I think feed-in tariffs are especially -- could be especially beneficial for the geothermal technologies, biomass technologies, and fuel cells with manure.

And so that sort of gets to the third question that you asked all of us. Feed-in tariffs can provide a great deal of certainty for these markets and I think all of these markets provide value to the ratepayers and this feed-in tariff would help address that value that they provide.

I think I will leave it at that for now.

MS. DOUGHMAN: Steven.

MR. KELLY: Thank you. I'm Steven Kelly, with the Independent Energy Producers Association.

And one, I want to thank the Commission for having this workshop, and not only this Commission, but the Public Utilities Commission in doing the analyses that are kind of addressing the integration of 33 percent RPS.

Because I think it's important that the State agencies begin the process of sending the proper signal to the public.

I mean, I'm amazed repeatedly that in the wake of AB 32, which is essentially transforming or attempting to transform our economy, people are asking the question, well, is this going to cost something? And I guess my answer has always been, yes, it probably will. You're going to change your economy from a primarily fossil-based economy to a primarily non-fossil-based economy, yeah, that may well incur some costs.

But what I'm happy to see in the studies that I've seen so far is that the costs really are not that significant given the uncertainties of the evaluation and the range of the things we're trying to do.

The PUC study, I think, indicates that there's a ten percent cost increase, potentially, for going to 33 RPS, it's a 2.8 percent incremental cost increase for going to the 20 percent.

Those are well within a range of, in my mind, reasonable, given the task that's in front of the State in trying to move to this new structure that we are trying to do.

So I think that's important and I think it's important that the agencies couch this in the proper language because it's often couched improperly, I think.

For example, we're read over the last couple of years a lot of studies about renewables, and the renewables need gas backup, natural gas-fired backup, and that's an incremental cost to the system.

I actually think of it as the renewables backing off the natural gas that we need, anyway.

I mean, in this State there's only two types of technologies, probably, that we're going to bring to bear, natural gas to surf load and renewables, there's not a lot of choices. So we've got to plan for both.

We've got to plan for natural gas to serve load. And when the wind blows at two o'clock in the morning, or whenever it is, it's backing off natural gas. That's probably a good thing at that point.

And, hopefully, we can build the infrastructure to create the potential for the electrification of the transportation sector. But we've got to start that sooner, rather than later, because if we wait it will never happen. Things will change, we won't have the infrastructure when the transportation sector's ready to kick into this.

So I'm here to encourage the Commission to continue focusing on this and looking at this as a positive. These costs are well within the range, in my view, of achieving the goals and the tasks. The public is probably well positioned to take these on as an increase in their monthly bill.

And all the public policy surveys that I've read to date, particularly in California, seem to suggest the public supports this.

Now, I want to reemphasize this issue that the focus shouldn't be the cost of the RPS per se, it's really the cost of AB 32.

And what is it -- what's going to be the cost of doing nothing? And we know we can't model that. I mean, it's possible we can model the RPS costs, so everybody does that.

The thing that's missing is what are we going to do if we don't do this? And that's impossible to model very accurately, in my view. And so it's an unknown, so nobody focuses on it.

But if the renewables, for example, can be used to electrify the transportation sector, can be used as a storage, so to speak, through that mechanism, that's a good thing and it's a positive thing and I doubt if we can really value that very well at this point in time.

So we are looking to make investments today to get the infrastructure in place to make policy implementation changes in maybe eight to ten years.

I just want to point out in that regard, I was at the Western Governor's Association meeting a week and a half ago, I guess, in Salt Lake City, and the Secretary of Energy was there, and I think it was him who made the observation that -- in this point about what are we comparing it to?

And there were people that were questioning climate change. But his observation was that what we're doing is buying insurance.

And he made the observation, with his Nobel laureate intelligence behind him, so I take it all without investigating, that the difference between the glacial period in North America, when everything was covered with ice, and today is like four degrees.

I read some stuff that suggests we’ve changed -- the temperature’s gone up a degree or so, a degree and a half in the last 50, 60 years.

But the point is that the change, it doesn’t take a lot to really, dramatically change the environment.

And what we’re doing in pushing an expanded RPS, combined heat and power energy efficiency and clean natural gas is buying insurance to prevent that change, and we can’t calculate what that impact of that change is going to be, and so we’re just going to have to do it on gut feeling.

And that’s kind of what the Legislature, I think, did as well.

I will note, though, a couple of observations in light of the reports. There’s a lot of focus on one or more of the renewable technologies and, you know, we’re going to meet 33 RPS with all wind, all intermittents. My God, we can’t handle this on the system.

It’s only going to be a portfolio approach of all the renewable technologies, supported by natural gas, that’s going to get us there successfully.

We know we need natural gas for load following, reliability, and all those reasons. Some of the renewables can provide some of those, biomass, geothermal, which aren't talked about very much, provide baseload amounts of energy that can be used, and very successfully.

We've got the solar, which is kind of a peaking resource.

And then there's the low-cost wind that kind of melds with the peak and then, hopefully in the future, will be serving to store energy in the transportation sector, electrifying vehicles.

So those all come together, they all have an individual role to play in transforming this economy.

But we need a portfolio, in my view. And analytics that focus on a scenario that is all intermittent is wrong on its face, in my view.

And if that's occurring, that means that the methodologies we are using to secure resources is misplaced, least cost/best fit isn't applying, probably, if all we're getting is intermittent resources that are going to require a lot of backup and support.

And that's probably where we need to look, to make sure that we are using the valuation tools, the procurement tools to minimize the costs of meeting these goals, and I have a feeling that that's going to take a portfolio across all technologies in the end of the day.

I guess the other thing I would just add, there was a discussion this morning about the over-gen situation that occurs and the reliability problems with that.

And again, when I hear that language about over-gen, I mean, over-gen has occurred in California since we had hydro, and we imported from the northwest. It's not a phenomenon of the RPS.

But as a matter of fact, if you end up in a scenario where you are backing down natural gas, in a low carbon environment in the future, you know, that's probably a good thing. You need the natural gas to be there, it provides amounts of incredible reliability for services. But if you can back it off in an over-gen situation, that's probably a good thing.

It would be very good if we could store that energy. And I'll note that in the legislation that's being discussed across the street, there's an attempt to get rid of storage of renewables in the State, as a means I think to minimize the amount of RECS. It makes no sense to us.

But that's something we've got to look at to make sure that we have a program in place that allows the renewables to be used for storage.

And the context -- I see Bob's saying where's that coming from -- it's the simultaneous delivery language in the legislation, everything's got to be delivered right away. That kills storage under the way the language is drafted now.

So we've made that comment in a letter we sent to the authors of the SB 14.

But simultaneous delivery and storage are incompatible in the way that it's currently drafted, and that's a problem and it doesn't serve a public policy purpose. So that's one observation.

The other thing I'll just say, kind of things to note of concern, the -- there's a lot of emphasis in the analysis about the 33 percent RPS, the huge increase in CHP, and the very, very large increase in energy efficiency.

Now, let me make a couple of observations and this may get to some of the modeling techniques.

But related to CHP, we are facing a situation where the PURPA must-buy obligation is probably going to be suspended this year, which means that that vehicle for bringing on new HC will probably not be available to people, and we may be moving to some sort of contractual mode. It's not clear whether feed-in tariff of CHP is implementable. People are talking about that.

I think anybody in the CHP business, myself, and some of the other trades that are in discussions with the utilities today, do not believe that those numbers are achievable, the 5,000 megawatt increase, under the programs that are being discussed today. So I'll just make that observation.

Energy efficiency. I've been around a long time, most of the energy efficiency has come through -- in California, I think, has probably come through this Commission implementing appliance standards and housing standards.

It's ironic that we're talking cap and trade, but we're in a situation where all the money from cap and trade is designed to flow back to the consumers to mitigate the rate increases, so they don't change their behavior.

So I'm assuming that there's not going to be all the energy efficiency that everybody's talking about, unless you can get it through building standards.

RPS, you know the track record there. Whether we're going to achieve 33 percent by 2024, or 2030, you're guess is as good as mine. The track record isn't so good.

So putting all that together, when we look at the costs of all of this stuff, and everybody's concerned about the implementations from a grid reliability perspective of having this stuff configured into the grid, I don't see it happening as fast as people would like, or I would like, so I take the concerns -- they're important concerns, from a grid reliability perspective, but I am not thinking it's going to be a concern that's going to arise on my watch by

2020.

I mean, I remember these debates being discussed ten years ago. And what did we bring on, 800 megawatts in the last seven years? I mean, you know, the grid can handle that.

So I guess to close would be to say that these studies are very important. I think we need to present them in a public in a way that doesn’t undermine the success of achieving these goals.

And on the analytics for the technical work, there’s people that are going to be working that and trying to get that smoothed out, and have a sense of what it’s going to cost.

But meanwhile that’s going to take many years. I think we do need to get moving on installing the new natural gas that we need to meet load demand, support the renewables, and so forth, and then bring the renewables on as quickly as possible.

Those are my comments, thank you.

MS. DOUGHMAN: Thank you.

Carl.

MR. ZICHELLA: Good afternoon. I’d like to thank you all for inviting me to be here. I’m Carl Zichella, I’m the Director of Western Renewable Programs for the Sierra Club. I’ve been working on a renewable energy transmission initiative, the Western Governors Association RES process. I've been working with other colleagues to work with the Department of the Energy and the Department of Interior on their renewable energy program for California and the west.

And I really appreciate, as my colleague said, this is a really important workshop, these are really important reports.

And I wanted to highlight a few of the things that I think we need to be looking at a little more carefully when we start talking about balancing resources and the pressures on the grid.

I'm not going to comment on modeling, I'm not a modeler, but I will mention a few things.

I think Steve said some of the things that I would like to have said and others I think I take a slightly different emphasis on.

I think we need to look at the possibility of how to balance renewables with other renewables in California. I think we have some timing issues that make us able to do some of that.

Of course, we have intermittent resources, but sometimes they will cycle on at different times.

Not only that, but I was pleased to see some of the studies look at the entire western interconnection, and reminding us that we're part of the entire western interconnection and there are balancing opportunities on the western grid beyond that.

In some of the RES work that we've done, we've noticed that Colorado wind can help balance Wyoming wind, for example. And I don't think we know enough about how external resources we're importing may be able to help us balance our renewable load.

I think there are issues with congestion on the lines that we don't have enough information about, that we're making some assumptions about congestion increasing costs, and increasing the difficulty of integrating renewables when, in fact we know that there are many long-term contracts that have been signed since 2001, that will be coming to a term on the next five, ten years, sometimes sooner.

These contracts may not necessarily be renewed. Some of them are for out-of-state resources that we may not need if we're bringing renewables on. If we're going to be, as LADWP is doing, trying to replace some of their coal load with renewables, that could actually free up a fair amount of capacity on that system.

One of the things I think we also need to look at is integrating our system more completely. I mentioned that earlier today, not having such separation between IOUs and the publicly owned utilities, so that we can actually take better advantage of the totality of our system and deal with some of these congestion issues and these integration issues a little more effectively.

On related policies that are affected by this, I think the distributed generation information we got today, from the Public Utilities Commission, was very interesting.

It does show a price parity coming into play under some scenarios. I think that that's really encouraging. But I think we have to look beyond just price as a driver for distributed renewables.

And by the way, it isn't always rooftop solar. Some of these very large commercial facilities, and also some ground-managed facilities of modest, more modest scale on disturbed private lands, as some businesses are beginning to look at.

There's the Edison Mission Company, that is a business plan looking at smaller scale, but still pretty big, I mean 100 megawatts or so, closer to load on disturbed private lands. They have a much easier integration play for us. And I don't think we've really looked at that intermediate model very much. It's all been pretty much rooftop and urban areas, and I do think this is a part of that bigger picture.

I think if we really want to see distributed generation accelerate in this State, we're going to have to look at some new policies.

Feed-in tariffs have been under investigation by the Public Utilities Commission, as well as the Energy Commission, and I think we need to look at incentives for scale.

Right now our policies are disincentive for individual homeowners or business owners to scale their programs, their systems for their buildings larger than their own needs, and I think that's a mistake.

If we're looking at trying to get a bigger increment to reduce the amount of transmission that we have to construct in this State, we ought to be providing incentives for scale, and that means pricing incentives up front so that people can get financing, so that they can actually have an investment that has a return on investment for selling their excess power back into the grid.

And we'll begin to see scaling of systems that actually will make a lot more sense, I think, for us.

This is a model that's worked in Germany. It's worked maybe too well in Spain, where they've had to roll their program back.

But I think if anything it demonstrates that having a system that provides incentives to build to a scale larger than your own needs is very effective.

Uncertainties, I think we heard a lot about gas usage, and pricing forecasts, and how all over the map they are, and we do need to reconcile those.

I think some of those scenarios make it look like renewables don't make any sense, and that's more than just counter intuitive, I surmise that something's wrong there.

I do think that needs to be straightened out.

Also, we saw some uncertainties today described between the net short between various entities. We need to sort of get more of consistent methodologies in the State so we have a better view of what it is we need to do in order to meet these goals.

I think I heard a lot today, and I think Steve did touch upon this briefly, is we're looking at the cost question too narrowly. We're comparing the costs in the future against the base case or against today's pricing. And while that's useful for getting a snapshot of the commodity price, it's not useful from a cost benefit perspective.

I think it's in fact the wrong question, the analysis is way too narrow.

The benefits of getting renewable power in have to be balanced against the cost of not doing anything, and the impacts that have been fairly well, I think, established in California, in the PIER program. There's been a lot of good research that's been done about the potential impacts of climate change.

I think it's very interesting timing that just yesterday the Secretary of the Interior was in Fresno to talk about a water shortage that has become retractable in this State, where farmers are having to idle large amounts of land, and our ability to bring species that are part of an ecosystem of great commercial value to California back is being compromised by an increasing drought. Which under every scenario forecast in California is going to get worse under climate change?

And one of the forecasts this State has made is an 80 percent reduction in snow pack by the end of the century, under business as usual scenarios.

And I have to say that the cost of that is just simply off the charts.

If we're just talking about electricity costs that are seven percent in 2020 than they are today, and that's the conversation we're having, I think we're really making a big mistake, and we're hampering the public's ability to understand why it is we need to do this in the first place.

The Secretary of the Interior also, today, announced a plan for the Mojave, to help identify areas for solar energy development on public lands that could -- that be expedited in terms of bringing them online. And also identifying these projects in places that are more easily permitted.

And what he means by that is fewer environmental conflicts.

A lot of those are going to overlap with zones that we’ve identified in a renewable energy transmission initiative, which has had a similar mission.

And I think that’s an uncertainty that actually could help address some of the timing issues, perhaps, that we’re looking at and our ability to meet this 33 percent goals.

There are issues that are not easily quantified in a model, that I think are going to have a profound impact on whether or not we’re going to hit these goals.

Some of that is inter-agency cooperation at the Federal level, and inter-agency cooperation between the Federal and State governments.

And I think that this new administration, and the interest of the State to solve that problem can really help us. I don’t know how you factor that into an analysis, like the IEPR, but I’ll just point out that that’s part of the context that we’re operating in.

Talking about the cost benefit analysis for just another moment, it’s been forecast by climate scientists that a one degree increase in temperature will lead to a 20 percent extinction of desert species.

And California has the second highest level of endemism of wildlife species and plant species in the United States, after Hawaii.

We have a great deal to lose if we don’t solve this problem. We need to have this continue to be part of that conversation.

I think, in the pace of technological innovation, the storage question has come up several times. If we can get a better sense about which technologies we ought to be promoting in order to help solve this issue, I think some people talked about thermal storage for concentrating solar plants. It’s feasible now, it’s practical now.

We should, perhaps, be looking at ways to create incentives for those to be deployed earlier on, to help smooth out some of the intermittency problems that we’ve been talking about.

There are others that technology’s actually moving fairly quickly. And I’m not an expert, or expert enough to sort of forecast when they’ll be commercially viable, but I think that is something we need to look at in much more detail.

What’s the outlook for capacitors, what’s the sort of timeline on those?

What’s compressed air look like? Do we have an opportunity to utilize that technology in California.

Molten salt, as I mentioned, we’ve already seen its end use in Spain already. There’s no reason why it couldn’t be used here, in California, to extend the peak that solar thermal plants produce.

I mentioned earlier, it’s sort of a pet peeve of mine, I’m going to say it again, combined systems and goals around the POUs and the IOUs, the publicly-owned utilities and the investor-owned utilities to help solve some of the congestion and pricing issues.

There’s no reason in the world why ratepayers should have to pay line charges for two or three separate entities, when we should have a combined system in the State.

And we will have a much easier time siting the transmission we need in California if we’re not having to have fights over duplicative lines in sensitive areas.

I think we’re starting to come to a real consensus about how to approach transmission in the State. A lot of stakeholders have worked now for over two years in the RETI process on this, the Renewable Energy Transmission Initiative.

And I think that there’s no reason to sort of pretend that this conversation shouldn’t happen or isn’t happening. We should be figuring out ways to make it happen as quickly as possible when it comes to combining the transmission assets for the use of both privately-owned and publicly-owned utilities.

I think I’ll stop there.

MS. DOUGHMAN: Thank you.

Let's see, Jeff Hahn.

MR. HAHN: Good afternoon. My name is Jeffrey Hahn, I'm the Director of Environmental for Covanta Energy.

Covanta's one of the several companies in the California Biomass Energy Alliance. And Julie is on the other side of Sacramento on SB 14, and that's one of the topics that I'll be talking about, so she asked me to step in.

I assume, from your report and your background you know a lot about biomass, but let me just reiterate some facts. Your own data show, and this was published early this year, from January 1st, of 1998 to June 30th, of 2008 that biomass actually supplied over one-third of the megawatt hours of all the renewables in California.

And so I think that's important to know that for the biomass industry, we need no transmission, because the fuel comes to us. That is part of another problem I'll talk a little bit later about.

We are base-loaded 24/7, we run like a regular power plant.

And the other is the co-benefits that we have in the field that we use. And co-benefits is a big part of AB 32.

We avoid methane, which is 20 to 25 times more potent than global warming potential.

When waste is left in the forest, from forest trimming, ag, from incomplete ag burning, and land filling, even with the new early action measures, materials that we take out of the landfill and use as fuel.

So we have now 33 or so operating biomass plants in the State, over 650 megawatt capacity. And as I said, our fuels are from the forest, from ag waste, and from urban waste.

But part of the urban waste that we get is not in competition with the people who are trying to make biogas, because the waste that we burn doesn’t have a lot of gas generating potential, as other biomass does, regular biomass from MSW.

So what are our issues. The first one, in particular, is getting enough electrical revenue for the power that we sell the IOUs and the POUs. That’s the subject of SB 14.

I’ve got a list here from Julie of all the things that happened with the type of contracts we have, where we’re getting less and less for the electricity we produce, and we have to buy the fuel, and we have to truck it to where we’re going to burn it, and those costs are going up.

So the plants, there’s also proceedings now, with the IOUs, to take back some of the money from the SRAC and go back into the years they’ve already paid us and try to recover some of that money. So that’s the first one.

And again, then, some competition for biomass.

Our fuel prices tend to go up, certainly with diesel, and there's also becoming some competition for biomass.

On the flip side of that, if we do not survive well, the dreams of ending ag burning by 2010 won't happen, because we are the place that can handle the ag waste, certainly in San Joaquin Valley, and we're in talks with the District there to make sure they don't back off from the implementation of no ag burning in 2010.

One of the most important things, that I can't stress enough, is something that's happening with the implementation of the scoping plan, and also at WCI, and that is the concept of looking at carbon neutral for biomass.

And I want to give you an example, from our six facilities that are over 135 megawatts. The report from CARB is about two months late on how they're going to handle this. They put it in the scoping plan and adopted it at the last minute.

When we report, as we have to CCAR, at least Covina from 2005 emissions, and this year we've reported our 2008 to CCAR, we separate the CO2 biomass from CO2E.

And to give you an example, for the 135 megawatts in six facilities we about 8,000 metric tons of CO2E, half of that's from start-up fuel, natural gas and propane, half of that's from reagents that we use to scrub out the acid gas, and a little bit of that, very little, is from the N2O and methane from the combustion process, but we use real data.

On the contrary, we have a million 300,000 metric tons of CO2 biomass.

So think of this, if for some reason that CO2 biomass creeps into and becomes CO2E, six plants would have to pay anywhere from, I think it's $10 a ton in the auction or -- the auction of a cap and trade system for the allowances, that's $13 million, up to 39 if it comes up higher over time.

Our plants can't afford them now, we can barely keep them operating on the electrical rates we're getting.

But if that happens, and that's both under the CARB, as well as cap and trade, as well as the Western Climate Initiative, and equal disturbing tendency is the language written into Waxzan-Markey, on the definition of biomass.

It doesn't affect so much the ag waste and the urban waste, but it does the waste from the forests, and which forests and some of the definitions there will not be good for additional biomass.

And this carbon neutrality from the Air Resources Board gets into the point of what can truly be carbon neutral if you have to truck the material, using fossil fuels, to your facility to burn it?

So that that issue has to be solved or your whole baseload and the Governor’s Executive Order to have a certain percent of renewables as biomass won’t be there.

And so your modeling and all the calculations, if something isn’t done soon, you’re going to have to start all over again because that other column that you saw this morning was all the biomass, and it could conceivably not be there if some things aren’t fixed in terms of the price we get for electricity and keeping us, our biomass CO2 out of CO2E and having us fall into cap and trade.

The last couple of comments, question nine and ten we can fit into the -- it’s not a concern for biomass, there’s only a certain amount.

Number 11, you know, again, we’re base loaded, we’re not intermittent, so we can help alleviate that issue, irrespective of what the other speakers have said for other technologies.

And again, number 12, you know, we just need better funding, as Carl was talking about, real funding, to keep renewables that have the part of the renewable portfolio standard, as well as all the air pollution co-benefits in terms of reducing things in the value like PM2.5, so from open burning.

And so I’ll end my comments now. But I’m not sure you’ve heard all that and how your models would be affected if the -- you know, the number of megawatt hours from biomass disappears before 2012. Thank you.

MS. DOUGHMAN: Thank you.

Is Martha online, available?

MS. DAVIS: Can you hear me?

MS. DOUGHMAN: Can you speak up a little?

MS. DAVIS: Yeah, hold on a second, I've got you on -- is that working better?

MS. DOUGHMAN: Yes, thank you.

MS. DAVIS: All right. Thank you very much for the invitation to participate in the discussion.

My name is Martha Davis, I'm the Executive Manager of Policy Development for the Inland Empire Utilities Agency. We're located in Southern California. We originate to distribute imported water supply within the Chino Basin and to provide 800,000 people. I sit on the Board of the Metropolitan Water District of Southern California.

We also provide regional sort of treatments to the southern cities located within our service area. And so we have basically three products, recycled water, compost, which is what we're using for the sewage sludge, and recycling it locally, and the producing renewable energy.

I also am currently the Chair of the Energy Committee for the Association of California Water Agencies, so I've been leading them in the last year on getting involved in renewable energy issues.

And my agency has got started really early, really on the energy crisis, on getting involved in renewable energy. And we're like the first public agency that gotten at the headquarters installed digester projects both for sewage sludge, and in partnership with the local dairy industry. So with the California Energy Commission's assistance, we looking at a regional digester down here in Southern California. And we've just installed 3.5 megawatts of solar energy.

And I think one of the things that I would bring to this discussion today is the need to really expand the context of the partnership among the different agencies that are trying to address both the Governor's objective for renewable energy and AB 32 implementation, and bring water and waste water agencies into a proactive discussion about what they could bring to the table.

Certainly, as the IEPR identified several years ago, the water/waste water industry is currently using about 20 percent of the energy usage in the State. There is certainly, because of the large amount of internal combustion engines, one of the target factors for helping to achieve AB 32.

And as in the article that was described earlier, we are directly in the crosshairs of the impact of climate change. So for us, renewable energy is as much about mitigation -- well, adaptation, as it is about mitigation, and will be a part of trying to address this bigger picture of impact of climate change on our long-term water supply.

If you flip around and look at it from the stand point of the partnership, we are one of the factors that are suggesting increased population, increased services, and significant increases in energy usage.

Energy is our most controllable cost center, so a higher cost center is typically labor, next to the energy, and then applying of the chemicals.

We have a great deal of interest in figuring out how to manage these energy problems.

But we also have a unique combination of capacity to develop renewable energy in having the wind, the engineers, professional staff, along with the load to be able to use particularly on-site distributed generation.

One of the key obstacles to doing that is, as we've identified by a number of participants is seeing the real value of the energy that is being produced. Our agency was a sponsor of the feed-in tariff, AB 1969, which currently has another bill just to help clarify the feed-in tariff, of SB 32.

We've also participated in legislation on net zeroing. All of those, within the last few years, are new policy directions aimed at one core issue, how to actually get the value of the renewable energy that is being produced back to the entities being affected and the facilities that create the renewable energy.

I want to also clearly state, and it’s been alluded to in today’s conversation, it is worthy of in particular, are some of the cross-impacts of regulations that will end up impeding some of the renewables development.

I think the one that jumps out as an example for me is the regulation of 1110.2, which basically addresses how much biogas can be combined with natural gas in order to run an internal combustion engine.

And this is getting at that balancing act of environmental impact between not wanting certain types of emissions, but the result of it is to become an obstacle for the ability to use a renewable energy, like biogas is, that could be produced by, in particular, the waste water agencies.

I think that I would surely support some of the comments that have been made in this panel, the need for the holistic planning. I think that’s one of the things that really jumped out of this morning’s conversation, in particular looking at some of the models. I’m not an expert on the modeling, but it’s clear that there needs to be at least some scenarios that deal with what’s a real approach and with holistic planning scenarios, and integrating a broader array of value to society of the investment which is being made.

I second the point that was made about the different scales of renewable energy investments. I think there's been a lot of focus on these really large plants. I think that we, in particular, are going to need renewables on many different scales. And I think the partnership with the water and the waste water industry, and the global government should think about is the ability to do a lot of smaller renewable generation, located or co-located with loads, or doing new load, and that's going to have, I think, a really exploding implication for some of the transmission issues that were discussed earlier this morning.

Another issue I just want to cull out, particularly on the pricing, is to go back to the notion of what is the value in these pricing studies.

One of the examples of where the State missed, unfortunately, on being able to get more renewable energy out of an incentive program was the California Solar Initiative, which was so focused on making sure that only one megawatt was -- or $1 million was being put in per site, which was appropriate, trying to cap the amount of money that was going into a site. But inadvertently it also capped everything at one megawatt per site.

And I know from a number of water, waste water agencies that participated in this program, that they would have been happy to install an additional one, two, three megawatts at each of the sites at their own expense.

Because what they saw in the incentive for the CSI program was intending to make development into installing the solar energy, but they clearly have -- for additional solar being installed, but they couldn't qualify if they went over one megawatt.

Very interesting example of well-intentioned plan that actually deterred the installation of more solar.

And just in closing, I think that one of the things we ought to ensure we want to do is get a better understanding of what the potential is within water, waste water agencies and work with government to bring renewables to the table. So we are working with some of the California Energy Commission staff, staff from the PUC, staff from our Aqua staff, a number of the waste water committee in order to put together a survey this summer that's trying to get at an understanding within the water and waste water sector of how much renewable energy, all different types, have been installed between 2001, and then how much more are water and waste water agencies currently projecting, and then trying to get at the same questions that you're getting at in terms of what are the obstacles that are preventing water and waste water agencies from doing well.

In accord with as we look at the partnership and the portfolio approach to try to get the State further to the goal line of achieving the 33 percent RPS there is, I think, a really unique opportunity to work with this particular sector that's going to be highly motivated to add a lot of capacity, to implement projects within the next five to ten years that could be an important layer in helping to achieve the goals.

And with that, I'd be happy to answer questions.

MS. DOUGHMAN: Okay, thank you.

And our last panelist is Dariush Shiromohammadi.

MR. SHIROMOHAMMADI: Thank you for pronouncing my name so well. That doesn't happen often.

I'm so glad to hear the presentation by other panelists, they cover so many of the important big picture issues that we need to keep in our sight and not lose sight of those important issues.

My presentation is going to be a lot more down to earth. And funny enough, I was thinking that my presentation will not be related to modeling. But when I look at it and especially when I put it in the context of other presentations, I see my presentation is all about modeling.

So once a geek, always a geek, I suppose.

One of the biggest issues here and, by the way, I represent California Wind Energy Association, which represents wind developers in the State, many wind developers in the State.

One of the biggest issues, you know, we have to deal with is the fact that on matters as important as this studies are performed by multiple agencies, sometimes even multiple studies within the same agency, which are not coordinated well enough with each other, for a variety of reasons.

As somebody who worked in one of these agencies, and I was so lucky to get CEC help me quite a bit, and we could do some coordination there.

But we run through extraordinary efforts on the side of both CAL ISO and CEC to make that happen. It wasn't happening easily.

One of my concerns is we see all these studies, with all these -- which are by and large focusing on the same outcome. The scope is different, but if CAL ISO, for example, is focusing on the amount of additional regulation they need, and you're focusing on the cost of integration of renewables, and somebody's looking at the cost of fuel, there are a few on greenhouse gases, you by and large would be studying a similar case, getting different results out of it.

So saying that the scope of these studies are different is not good enough, especially if the results come out in such a way that if I take the California ISO, the study on the amount of regulation I need, and I compare it with the study that CEC did on greenhouse gas reduction, and I see everything is different in them, that confuses me as a stakeholder, it confuses the public.

And, of course, CEC and CAL ISO are not the only entities who are doing these type of studies, CPUC does its own studies, and utilities, they do their own studies.

My concern is all these duplicative -- well, let me not call them duplicative, but all these complementary studies who, for a variety of reasons, do not start from the same point, do not end up -- which do not end at the same point, are at least confusing me as a stakeholder, and the constituents we have.

And as such, I’m sure that they will confuse the general public even more, especially as we just saw this morning, one entity says we’re going to spend more gas, then another study says we’re going to be burning less gas, and I guess both studies came out of the same -- the same organization.

So my point there is that we need to find a way of having, given that all of us are in the same boat, to put the resources together and try to do a one set or one consistent comprehensive study.

And especially avoid presenting results which may be completely -- the fact that they came off of a model doesn't mean that they should be presented.

The second point I'd like to make is what I've noticed, I was one of the central members of the NERC team, which worked on the -- and thanks, Danielle for bringing that up, made my life so much easier -- that studied the integration of large amount of renewables in the system, and we looked at it from reliability stand point.

Our first tendency was to look at, okay, this is the way the system is, this is the way we operate and plan, and operate it, what's going to happen if we increase all this wind, and solar, and all that stuff, ocean power and so on, what will happen to it?

Some of us, who have been in this business long enough say, no, no, no, hold on, the rules that dictate the planning and operation of the system were developed decades ago under very unique -- well, I can say, as a long-term transmission operator and planner, under simplistic conditions, to make the life of the operator and planner easier.

I mean, well, I must say we didn't have the mathematical tools to do better.

We are taking those rules, we're bringing them, all these models have them in them, inherent in them, and we're saying what would it take to integrate a lot more renewables into that model?

And, of course, we see all kinds of funny results coming out on the other end.

We need to basically, fundamentally question what is going on, how the system is planning for build, operated today. And that's what we're doing as part of this NERC.

I mean, NERC, the most conservative organization when it comes to engineering and reliability issues, have agreed to fundamentally question all these matters. And we are going to do that, we're going to the next space and, of course, we'll continue to evolve in a significant fashion again before we do an analysis of what it takes to integrate renewables.

We've been planning the system based on old deterministic planning standards, and those old deterministic planning standards always come up showing we need a lot more transmission to integrate renewables, and they always show that with the given transmission we can integrate only so little renewables.

If we could fundamentally went to what everybody else does in planning any system, any system is planned based on probabilistic approaches, except for transmission, where we use deterministic approach.

And they came about, as I said, for reasons that existed decades ago. A lot of people here weren't born when we came up with those rules.

And, of course, NERC agreed. One of the best things about this NERC Task Force is they approached the matter with a complete open mind, rather than the traditional approach that we utility types take. This is the way we operate the system, now fit within it.

The idea is, no, we need to question the way we've been planning and operating the system.

So I would like to say that a lot of studies we're doing have fallen, and the results I see are falling within the same trap, where we think that the system will be planned and operated in the same old way and as such, the results that we get are going to be significantly conservative, the costs will be significantly higher than they would be, and the requirements will be significantly higher for integrating renewables, than it would be.

So we need to question those fundamental rules. As we speak, CAL ISO is trying to work out a reserve sharing arrangement with BPA, which will help tremendously with integration of renewables in both service territories.

If we assume that that doesn't exist in our planning stage, our operational stage, or whatever integration studies we do, we are -- and by the way, NERC is working on modifying its rules, which are a combination of reliability and economic rules, based rules. We like to think everything in their model is reliability, but it's not. To see what rule changes keeps the system reliable and allows for additional significant voluntary integration of renewable resources.

And in line, and the further point I'd like to make, and the last point I'm making, is and in line with that just observation, we need to stop looking at renewables simply as some random negative load. That's most of the integration sources studies they do that, unfortunately.

The new generation of renewable resources are as controllable, and as powerful in being controllable as any gas plant out there. It can provide you with regulation, within their capability they can provide you with reactive support, they can do a lot of things.

I'm not saying, assuming that they're going to be all fully controllable, but even assuming them to be ten percent controllable will make the results could be significantly different that we get today.

So we need to also be a lot more open-minded about the way these resources can contribute to the reliability of the grid, than we have done in the past, which is sometimes ends up with some results which are not consistent with common sense.

That's it, I thank you very much.

MS. DOUGHMAN: Commissioner Byron, did you have any follow-up questions for the panelists?

COMMISSIONER BYRON: I do have a couple and I'll take advantage of asking them now, just because I apologize, I'm going to go need to join a conference call at three o'clock, and you may all finish before I get back, but I will try and be back around 3:30.

I'm just skipping through some of my questions.

Mr. Kelly, you said something earlier about not believing the high CHP, and energy efficiency and RPS may not be achievable. But back to CHP, what do you attribute that lack of achievability to?

MR. KELLY: Well, a couple factors. Let me -- first, there's going to be -- if what transpires in the way the PURPA must-bias is suspended this year, there is going to be a period of time when new CHP is going to have kind of an uncertain vehicle about how they're going to come before, either whether it's going to be a contractual approach, or going to be some kind of feed-in tariff.

So there's going to be a period of time that people would just -- all development of CHP's going to stop.

Secondly, in the context of discussing a remedy for CHP, which is contractually based, an RFO kind of approach for bringing on CHP, there's a lot of focus on setting a standard for participation in that program, a certain efficiency level, for example, or whatever.

Irrespective of that your CHP, you’ve got to meet a certain bar to be bidding into the CHP, because that’s what we want from a GHG perspective.

The people that I’ve talked to, on the technical side, think that there’s limited capability for new projects to come in if that bar is set too high. Or just because from a business perspective, if you’re doing new CHP, you’ve got the electrical side that’s got to negotiate a deal for the thermal host side.

The alternative for the thermal guys, I’m just going to put it in a boiler and I’ll deal with it that way, but I can do it right away, but I can get it going and I’ll run.

And right now we’re faced -- a lot of businesses are facing that choice, and it’s my understanding there are a lot of businesses that are in the process of actually changing out some of the existing CHP and putting in boilers, because of the certainty that it gives them from the business, from the thermal host side, food processors, or whatever. They know that they can at least get the energy that they need to run their plants.

So this absence of complete certainty, that I think has the potential of persisting for a while, is going to stall new CHP, for that’s the first thing.

And the second thing is how much can you get in the world to come to the fore, when you've got to bid into an RPS kind of, RFO kind of context.

Well, small businesses, hospitals, and so forth do that. I have doubts that they will do that. I mean, under standard offered contract it was relatively simple to do, right, you would have some consultant come to you and say, listen, here's the contract, here's the price, boom, boom, get it all, pull it all together and here you go.

If somebody has to put together a bid packet, and you're working with a hospital, or a jail, or whatever you're working with, any kind of institution like that, it's going to be measurably more complicated, I think, to initiate that process and get it completed, and put in your proposal and compete in that kind of context.

So I think that uncertainty's going to hurt CHP as we unfold over the next four or five years.

COMMISSIONER BYRON: Well, I'm quite concerned about this. I'm also concerned about some of the comments that Ms. Davis made about missing opportunities with solar limits on incentives. And we're missing an opportunity here, I think, with private capital and in the marketplace, and bring the very GHG reducing technologies to bear that we're looking for.

A quick answer, if you will, 700 to 800 megawatts in the last seven years, renewables, aren't you seeing -- won't you concede that we're seeing some significant improvement, a lot of contracts have been signed of late.

MR. KELLY: There are lots of contracts.

COMMISSIONER BYRON: That's all?

MR. KELLY: I have not seen that much operational. I mean, I think this year I read a report, I think from the Energy Commission, that there was going to be 150 megawatts that they expected to energize this year.

COMMISSIONER BYRON: Well, given that, Mr. Zichella, this topic actually came up earlier, maybe in a slightly different context, about what I'll characterize as the permitting, and the contract, and the construction failures. You know, it's not a hundred percent guaranteed process when we initiate a renewable generation or transmission project, but yet you made some comments earlier about wanting to reduce the number of lines that we see, POU, IOU coordination of efforts.

Do you acknowledge that we might need to see some more projects than we'd care to, knowing that some of them will not come to fruition?

MR. ZICHELLA: Yeah, I think that's just prudent planning. I mean, in RETI we actually have done that.

COMMISSIONER BYRON: Right.

MR. ZICHELLA: We're looking at, I think it's 160 percent of our RPS goals is what we've been planning for and trying to plan some transmission for it.

The good news is a lot of the project interest is in areas with existing corridors and where the existing transmission assets are. And while it's true that we may have to go in and replace some towers, and do some other things, I mean, to upgrade our existing system, we can actually take advantage of a lot of what we have. And that's really good news for getting this done quickly.

New rights-of-way is really where you run into the problems with siting, and public comment. And if you can stay within existing rights-of-ways, and best of all worlds deal with upgrading existing infrastructure, that's so much simpler to deal with from the environmental conflict, from a local concern point of view.

In many ways, the local concerns are often much greater than the environmental issues are, where people don't want a transmission line running by their house, or whatever.

I mean, it seems to me this is one way to really reduce those kinds of conflicts and get stuff built more quickly. If we need some new lines and we are going to build some new lines, that's great, we should be using the existing corridors that we have because we've already chosen those for a good reason.

And while other states in the west have had problems with their corridor selection process through the Federal process, through so-called 368 corridors, section 368 of the Energy Policy Act of 2005, California did a pretty good job selecting corridors in that process, and we're going to use those corridors, too.

So I do think we want to reduce duplication. We can take advantage of a lot of what we already have. That doesn't mean we're not going to make major upgrades to the system to accommodate lots of power, and including greater than 100 percent of what our RPS goals are.

COMMISSIONER BYRON: Other commenters were very good. Mr. Shirmohammadi, I'd like to thank you very much. I got your message, actually a couple of messages with regard to your comments, I appreciate them.

I'll defer back to you, Ms. Doughman. And again, I apologize, I'm going to have to cut out shortly. I hope to be back. But Ms. Brown will still be here at the dais, and Robert will as well. And I hope to be back, too.

MS. DOUGHMAN: I just have one follow-up question. I didn't -- I'd like to ask the panelists to share your thoughts on question 12, "what impact will the exhaustion of above-market funds from the CPUC for two of the three IOUs have on California's ability to meet the 33 percent RPS goal?"

I think some of you mentioned it in your comments, but if you could just go over your thoughts on that again, that would be helpful.

MS. OSBORN MILLS: This is Danielle Osborn Mills, again. I think two things need to happen in order to figure out what will happen if the above-market funds are exhausted.

The first is that I think we need some clarity. Resolution E4199 states that if the above-market funds balances, and it sort of neglects to answer the question of what happens to utilities' compliance obligation once the above-market funds are used up.

So know that while the IOUs are not required to procure any new renewables about the IPR, they're still encourage to procure below the NPR, but it doesn't necessarily state whether they still have a compliance obligation to meet 20 percent. So we need some clarity on that.

I think, second, what we need to do is establish some criteria for project viability, which I know the CPUC is already working on. But we need to take a good, hard look at what some of the contracts are and how they're -- whether or not they're underway and whether or not they're going to be built.

So we need to look at commercial experience, financing, some regulatory challenges, and find out which contracts are using the above-market funds, and whether they'll actually be build.

And I also think this is something that we should consider fixing in the 33 percent RPS.

MR. KELLY: This is Steven Kelly, with IEP. And I think assuming no change in State law, which is obviously being discussed as we speak, the effect is that the discretion to enter into new renewable contracts, or forward utility-owned generation contracts, or projects is going to be a discussion of the utilities, they don’t lose that. And then the Commission will have to determine whether it wants to go forward with those or not, at that time.

It probably, you know, will make it more difficult to move projects forward.

I agree that if there are projects that have executed agreements and are not moving forward, and it’s been a period of time so that there’s no likelihood that they are going to go forward, we ought to figure out a way to maybe free that up.

Either expanding the size of the pot so that the contract that’s been executed isn’t harmed, I’m not interested in doing that at all. But if it’s going to be a lengthy period of time and there are resources that we can reconfigure to move projects that are more viable, we should consider ways to do that without abrogating contracts.

IEP has worked very closely with the Commission on the project viability, which is designed to help inform that process that could be used.

MR. ZICHELLA: I don’t really have anything to add to that.

MR. SHIROMOHAMMADI: I’ll pass.

MS. DOUGHMAN: Jeffrey?

MR. HAHN: Well, we’re just hopeful that the legislation currently pending will reform the process, the RPF funding process.

MS. DOUGHMAN: Can you expand?

MR. HAHN: Well, get more money for renewables, change that market reference price.

MS. DAVIS: Yeah, this is Martha. I think that getting to a point where do for a green price, or the market reference price would be very important. But it isn’t just that price.

I think that making sure there are an array of mechanisms by which projects can recover the full value of their investment, the net programs.

But what it is now is almost a smorgasbord of options that allow investors to look at what combination would end up looking best for them to ensure that it’s moving forward with renewable energy projects.

For some, particularly, other agencies, the water and the waste water agencies, the net programs have actually been proving very effective at being -- for those programs to be in place.

MS. DOUGHMAN: Okay. I'd like to open things up, now, to any questions we have from the audience in the room.

MR. ELLIS: I'm Jack Ellis, here for WPTF.

Several of the presenters talked about feed-in tariffs, and I believe you talked about the adequacy of compensation for your biomass projects.

And I guess there were also some talks this morning about the need for system resource flexibility.

I wonder if those of you who advocate feed-in tariffs could talk about how they would work in an environment where we need as much flexibility from the resources that we connect to the grid as possible.

MR. DAVIS: Speaking from the market data, speaking from our agency's perspective, the feed-in tariffs have been, particularly for the smaller size projects, if you look at the projects that it's moved forward, the big gaps, if you will, are the programs that have been in the ten megawatt range.

And a lot of that gets at two issues. One is the issue of the value of the NPR.

But the second is the need for a simple tariff, and paperwork, and simple inter-connect agreement.

So that for a three megawatt project you're not going through hundreds, and hundreds, and hundreds of pages of contracts.

So coming up with a feed-in tariff that can be appropriately scaled to take advantage of a lot of the smaller projects, in and of themselves, they're not going to be the silver bullet on achieving the 33 percent RPS, but they clearly can play a very significant role as total portfolio approach. And to make it work, you have to have a feed-in tariff that is scaled to the size of the project.

MS. KELLY: Jack, this is Steven Kelly, again.

First, assuming the State has the authority to implement a feed-in tariff, which is being discussed, there are -- there are actually two structures for a feed-in tariff, one is what I call a standard contract, you sign the contract, off you go.

The other is you get paid when you deliver to the grid and here's what you're going to get paid, and you really don't have a contract. You use kind of a tariff basis from some mechanism to pay people.

Under both those structures, whichever approach it's taking, in order to deal with the variability issue that you've described, I think you can -- it's not the case that you need to have, necessarily a single price across all technologies, because all these different renewable technologies can provide a different product, essentially. Some can provide base load, some might be able to conjure up a little load following, and so forth, all of which might be priced at a slightly different level.

And I think you could use the pricing signals of a feed-in tariff to moderate the integration of the new renewables over time, to minimize the reliability issues that might pop up.

You can set a cap for the number of megawatts that might come through that kind of structure, as well, to help moderate reliability concerns.

And I think you can use it as kind of a -- I think of it as using it of kind of a toggle or a baffle to moderate the flow of the renewables through that structure.

I look at a feed-in tariff as a complement, not a replacement to the RPS/RFO structure, as well, so you can set it and see which one -- California’s position, to actually experiment with those and see which is more effective in bringing on viable renewables in a quicker time frame, and assuming we can actually do a feed-in tariff under the law.

MR. ZICHELLA: Yeah, the point I was trying to make about feed-in tariffs is we are going so slowing with distributed generation, it’s really painful to watch.

And if we’re going to have an impact on how much remote renewables we’re going to need, and how much transmission solutions we need to move that much remote renewables to the load centers, we need to look at how we can really accelerate what it is that we're doing.

And the way our incentives are structure right now, there's real limits on what people can do. Whether you own a large commercial structure or you own a home, there are limits to how much you can generate. And with net metering, especially at the smaller end of things, you know, no one's going to put a system on their house, that they have to finance, themselves, if they can't sell their excess power back to the grid.

So, you know, as far as the reliability questions go, you know, I think there are going to be reliability issues with it, but it is a very useful power source that does not require these really intensive, difficult transmission solutions to wield, and we can really ramp up a greater percentage of what it is we're trying to accomplish here with renewables, if we can come up with the right sweep of incentives in order to do that.

Feed-in tariffs give you that kind of investment assurance. You can get financing. If you know you're going to be able to get a certain price for a certain period of time, for example, as Steve just said, there are ways to adjust tariffs.

In fact, in Germany they do have technology-specific pricing. Spain has set caps, as Steve described.

We have models to look at out there, we don't have to completely come up with them, ourselves.

I think that the possibility of enacting one at a State level is very good. There's a fair amount of belief that the State already has the authority to do feed-in tariffs, but there's interest at the Congressional level to clarify that, to make sure that states have that authority. Whether it's as a component of compliance tools and how to implement a national, renewable electricity standard, or just a free-standing bill, as Representative Inslee has proposed for feed-in tariffs, I think those issues are going to be clarified.

As far as the grid reliability issues, I think it's going to have to be viewed in the context of the entire portfolio.

MR. ELLIS: Go ahead.

MR. SHIROMOHAMMADI: I'd like to make a point related to this issue. While I know exactly what you're saying by bringing up the issue of feed-in tariff, that's one way of, as you say, putting certainty, rate certainty, investment recovery certainty to renewable developers.

If looking at the California ISOQ, or Midwest ISOQ, generation Q, is any indication, there seems to be incentives out there. Additional incentives are always good and people, a lot of renewable developers are using the existing program, existing regime to bring in the ware to the market.

If there is any -- to me, if there is any of those expenditures that could a lot more significantly promote renewable development than paying one way for development, or one megawatt for rooftop solar, or whatnot, is of -- payment guarantees for technologies that help with integration of renewables.

We're talking about, for example, storage, where maybe there could be some sort of a payment guarantee, or feed-in tariff for developing storage, or transmission lines and so on.

So I know I took this a bit farther than what you wanted to hear, but what my thinking is, if the purpose of providing investment guarantee, I think they would probably get more out of it if they are made in the areas where it helps the existing developers, even to help them with -- give them additional incentive to bring the power into the system.

MR. ELLIS: Well, let me follow up with another question, then. If we --

MR. HAHN: Do I get a chance?

MR. ELLIS: Oh, I'm sorry, go ahead.

MR. HAHN: Just because we're based loaded, we tend to forget about us.

MR. ELLIS: Actually, you're the one I had in mind.

MR. HAHN: I have my cheat sheet from Julie here, if you'll pardon me for reading.

Again, the advantages to the IOUs, the long-term stability of the installation from volatile fossil fuel prices, and the retention of existing renewable biomass base of generation, and part of that comes -- and, obviously, these are our suggestion, because SRAC has been below seven cents a kilowatt hour since October of 2008. So we're really getting hurt on that, for the plants that have SRAC.

What we have proposed is a new fixed-price agreement starting immediately, no later than 1/1/10. Open season for enrollment, open to all biomass plants. The end of capacity payments it received, and also the end of capacity liability is dissolved.

A production guarantee posted equal to three months of gross revenues. The term's so that the contract run the shorter of the current contract or 12 years, and start at 9.35 cents per kilowatt hour, and escalate at 2 and three-quarters percent a year.

So that would keep the biomass industry running, you know, if we can have this come out. But if continues as it is today, we won't be viable if the electrical -- what we're paid for electricity is a lot less, like where SRAC is now.

MR. ELLIS: Thanks.

MS. DOUGHMAN: Are there any more questions from the audience?

MS. KOROSEC: Pam, I do have some public comments that I need to read into the record. They're not specific to this panel, they're just more on the broad topic of integrating renewables.

A public member was not able to attend and asked that these three paragraphs be read into the record.

"The proponents who believe global warming is caused mainly by manmade greenhouse gas have convinced Governor Schwarzenegger and the California State Legislature to mandate that investor-owned electric utilities in the State sell electricity generated by renewable energy resources. The mandate for 20 or 30 renewable cases several problems. First, a 20 or 30 percent reduction is a Band-aid approach when, to be effective, an 80 to 100 percent reduction is required to have a meaningful effect on warming.

Second, there's no way that the energy sources mandated by the Legislature can provide 24/7 reliable electricity in the amounts that the public and industry require. The sun shines a limited time per day, wind energy is fickle, both are diffuse and require large installations to produce small amounts of electricity. They can be used only if they're backed up by reliable energy sources, a very expensive operation.

The CEC can hold workshops on how to overcome the deficiencies of renewable energy from now until doomsday, but there’s simply now way that the CEC can juggle the effects of energy conversion to make renewable energy an economical or meaningful way to reduce greenhouse gas reduction in meaningful amounts.

An 80 to 100 percent reduction in greenhouse gas reduction could be accomplished by using nuclear energy, but the CEC is not willing to tell the Legislature that this is the only practical way to achieve that goal. There is always lurking in the background the question of whether global warming is really due to manmade activity and, thus, whether all of this agonizing is futile.”

MS. DOUGHMAN: Any reactions from panelists?

MR. ZICHELLA: Well, it’s not legal to build nuclear power plants in California right now, for one thing. And for another thing they’re more expensive to build for real dollars, in real dollars, than they were in the 1980s. You can hardly find a more controversial siting problem.

If we think that transmission siting is problematical, you ain’t seen nothing, yet.

I think this is technology that still has the same flaws it had 50 years ago, it still hasn’t solved any of its major problems. So I can’t see us making a major contribution, from nuclear power, to solve global warming under any circumstances. Not the least of all, you know, the only forge that's capable of building nuclear reactor vessels in the world is in Japan. We're not going to be building a lot of nuclear power plants.

MS. DOUGHMAN: Any other comments from panelists.

MS. DAVIS: I thought that was succinct.

MS. DOUGHMAN: We can't hear you very well, Martha, can you increase your volume?

MS. DAVIS: I thought that was succinct.

MS. DOUGHMAN: Succinct, okay.

MR. ZICHELLA: That's something I don't often get told.

MS. DOUGHMAN: Any more questions from the dais?

MS. BROWN: No, but are there other public comments from anyone in the audience?

MS. DOUGHMAN: On WebEx or on the phones?

MS. KOROSEC: All right, all lines are open on WebEx, if you'd like to make a comment?

Hearing none.

MS. DOUGHMAN: I think we're ready for closing comments from the dais.

MS. BROWN: Okay. Well, for those of us remaining, we do appreciate everyone's participation today. I think we covered a wealth of subjects, starting this morning with the utility presentations, we heard about logistics, we heard about the costs, we heard about the PUC's efforts to put their arms around some of the costs and benefits of renewable energy.

And I was especially interested in the panel this afternoon on some of the issues that you see, some of which we've heard before and we continue to work on these issues, right, the feed-in tariff, the net metering, the contracting issues.

I didn't hear a lot about regulatory streamlining or permitting, but I think that still remains an issue for the large solar thermal plants.

So I didn't have anything further. Again, on behalf of Commissioner Boyd, we thank you for being here.

Bob, did you want to comment?

MR. KINOSIAN: I just wanted to thank everybody, I thought it was a very informative workshop today.

MS. BROWN: Great. And we appreciate Commissioner Byron being represented, as well.

So I think with that, we stand adjourned.

(Whereupon, at 3:12 p.m, the Joint Committee Workshop was adjourned.)

--oOo--