STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2008 Integrated Energy Policy Report Update and the 2009 Integrated Energy Policy Report	)	Docket No. 08-IEP-1
	)	
and	)	
	)	Renewable Energy Feed-In Tariffs
Implementation of Renewables Portfolio Standard Legislation	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, OCTOBER 1, 2008

10:05 A.M.

ORIGINAL

Reported by:
Peter Petty
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel

Jeffrey D. Byron

Karen Douglas

ADVISORS PRESENT

Timothy Tutt

Panama Bartholomy

STAFF PRESENT

Mike Leaon

Joseph Fleshman

ALSO PRESENT

John Bohn, Commissioner
Robert Kinosian, Advisor
Molly Sterkel
California Public Utilities Commission

Wilson Rickerson
Rickerson Energy Strategies, LLC

Robert Grace
Sustainable Energy Advantage, LLC

David Hawkins
California Independent System Operator

Karin Corfee
KEMA

Marci Burgdorf
Southern California Edison Company

Bill Golove
Chevron Energy Solutions

ALSO PRESENT

Andy Katz
Breathe California

Eric R. Klinkner
Pasadena Water and Power
California Municipal Utilities Association

Craig Lewis
GreenVolts

Valerie Winn
Pacific Gas and Electric Company

Laura Wisland
Union of Concerned Scientists

Gary C. Matteson
Matteson and Associates

Pete Gregson
Advance: Solar, Hydro, Wind Power, Inc.

Julie Blunden (via teleconference)
SunPower

Richard W. Raushenbush
Greenvolts

Carl Zichella
Sierra Club

Tom Faust
Redwood Renewables

David Townley
Infinia Corporation

Steven P. Chadima
EI Solutions and Energy Innovations

Misti Norton
ET Solar Group

Kelly Desy
SolFocus

ALSO PRESENT

Chip Bissell
Silverwood Energy

I N D E X

I N D E X

P R O C E E D I N G S

10:04 a.m.

MR. LEAON: Good morning. Welcome to the California feed-in tariff design and policy options workshop. We'll go ahead and get started.

For the record my name is Mike Leaon. I supervise the Integrated energy and climate change unit with the renewable energies office.

I have a few housekeeping announcements to go over before we get started. First, in regard to those of you that are participating in the conference over WebEx, I do want to let you know that you will be able to see all the presentations over WebEx.

Also, if you're interested in making a comment or asking questions, you can click on the raised hand icon to pose a question to the WebEx Administrator; or you can chat directly to the WebEx Administrator.

WebEx users are all muted on entry, so you will be able to hear the workshop but we won't be able to hear you. However, during the question-and-answer portions of the workshop we will unmute the WebEx users so that you'll be able to get some questions in. And log-in details are

on page 6 of the notice for those of you who are interested in participating over WebEx.

A few brief housekeeping announcements. We do have handouts that are on the desk at the entrance to the hearing room. Restrooms are located on the first floor directly across from the hearing room. We have a snack bar on the second floor. You go up the stairs to the second floor and diagonally across you'll see the snack bar.

Also we have several restaurants within walking distance of the Commission. And if you're interest in grabbing a bite to eat at lunch, you can catch CEC Staff and they can tell you the nearby restaurants.

In regard to emergency evacuation procedures, in the event of an alarm, we will have to evacuate the building. And we'd ask that you follow CEC Staff out the main entrance on the 9th Street side here. And we will evacuate to Roosevelt Park, which is kitty-corner from the Commission across the intersection of 9th and P. And we will, hopefully, if in that event, get the all-clear to come back and resume the workshop.

A few ground rules. For those of you

that want to make comments today, for those of you in the room, we do ask that you use our blue-card process. Blue cards are available on the table, again just inside the entrance to the hearing room.

We ask that you turn in blue cards to Energy Commission Staff. And if my staff can raise their hands so everyone knows who to give their blue cards to. Staff will get those cards to me and I will call upon people that have submitted the cards to come up and speak.

And we do ask that you provide a business card to our court reporter, who is at the end of the table here. And also be sure to use the microphone because those that are on WebEx will not be able to hear what you're saying unless you're speaking to a microphone. And that's also important during dialogue later this afternoon, that we don't have questions out of the audience. That we really need to have you use the microphone.

And, again, we will provide time for WebEx participants to ask questions, as well.

So, a little bit more on Q&A format. We'll take the blue cards first, followed by WebEx

participants. And, again, you can use the raise-hand icon to let the administrator know you have a question or email directly.

For those of you that are only on the phone, we will provide some time during the end of the Q&A sessions to see if we have questions from folks that are only listening in on the phone. When we unmute the phones, it's important that you keep your phone on mute. Otherwise we're going to pick up a lot of background noise. And only unmute your phone if you have a question.

For the agenda today, we have Commissioners that are in attendance for the staff workshop. I want to thank the Commissioners for being here today. After my introductory remarks this morning, we'll see if we have any comments from the Commissioners.

And following that I'll provide some background information regarding our goal for today, a brief summary of some of the feedback from the June 30 workshop on the issues and options report. I'm going to also be discussing the policy drivers that were used to help formulate the policy paths in the report that's the subject of today's workshop.

We'll then hear from Wilson Rickerson about the experience of feed-in tariffs in Europe. And also from Bob Grace, who will go into detail on the development of the policy paths that are in the report, their potential interactions and potential for use of trigger mechanism with those policy paths. Wilson and Bob are both part of our KEMA team, our contractor for this project.

Following Wilson and Bob's presentations, we'll hear from the CPUC. Molly Sterkel is here today to provide us with an update on the under-20-megawatt CPUC proceeding for a feed-in tariff.

And at that point we'll break for lunch, and then resume after 1:15. We'll have a panel discussion post-lunch. And following the panel discussion there will be time for stakeholder comment and feedback.

At this point I would like to ask Karen Douglas, the Chair of our Renewables Committee, if she would like to make any opening remarks. This report is being prepared under the auspices of the Renewables Committee.

COMMISSIONER DOUGLAS: Thank you very much for that introduction, and thanks to

everybody for being here today. This is a staff workshop on the second draft report on feed-in tariffs called California Feed-in Tariff Design and Policy Options.

As you see there's tremendous Commissioner interest in this topic, as well. I'm joined on the dais by Chairman Pfannenstiel, Associate Member of the Renewables Committee, and also of the IEPR Commission. And on my left, Commissioner Byron, who is the Presiding Member of the Renewables Committee.

I'm told we will be joined by Commissioner Bohn of the PUC in about a half hour. His Advisor, Robert Kinosian, is here on my far left. And on my right, Panama Bartholomy, my Advisor. And my far right, Tim Tutt, Advisor to Chairman Pfannenstiel. So, again, we welcome everybody here.

The 2007 IEPR Committee asked the CEC Staff to prepare a whitepaper in collaboration with the CPUC to explore possible designs and options for feed-in tariffs that could work in California. And to initiate an analysis of the pros and cons of using feed-in tariffs in California.

We are now looking at the second draft report. We developed an initial draft report called, Exploring Feed-in Tariffs for California, Feed-in Tariff Design and Implementation Issues and Options, that was the subject of the June 30th workshop.

Staff is seeking to obtain input from interested parties to include in a final report to be issued in November. And we are also tremendously interested, the Commissioners are very interested in both the presentations by staff and others here today. And public comment on the draft report that we've put forward.

With that I'll ask if other Commissioners have any opening remarks.

CHAIRPERSON PFANNENSTIEL: Thank you, Commissioner Douglas. Just briefly, as one of the members of the 07 IEPR Committee, the reason we were so vitally interested in feed-in tariffs is that we recognized, as this Commission has said many times, that we weren't meeting the progress for the RPS goals that we had set our for ourselves.

And fundamentally we're asking the question of why not. What's in our way. We

identified many obstacles and many potential obstacles, some that some people raised and said this is the problem, and other people said no, it's not there, it's somewhere else.

Well, one of the potential obstacles was this question of contracting and whether it's a problem in terms of the procurement process that is currently used for renewables in the RPS. And we examined the experience in Europe, where especially in Germany and Spain, where they've had a feed-in tariff. And looked at the difference in ability to bring online these renewables.

And so asked the question, well, is that a possible solution in California. It was with that background that we then asked the staff to prepare us a whitepaper and consideration of a feed-in tariff in California.

So I'm looking forward to the discussion today. I really do appreciate everybody being here for this workshop. I think it's going to be very meaty, and I'm hoping that we can come away with a better understanding, both of what has worked elsewhere and what might or might not work in California.

COMMISSIONER BYRON: Thank you,

Commissioners. I'll be brief. We're behind on renewables, we're not meeting our goals. The IEPR Committee is certainly interested in feed-in tariff as a possible way to do that. And I'm really glad to see fellow members of the PUC here today. I look forward to hearing Ms. Sterkel and I'm glad to see that Commissioner Bohn and his Advisor will be here.

We definitely want to try and get this right, and we look forward to working with the PUC figuring out a path to get us there. Thank you.

COMMISSIONER DOUGLAS: Very good. Please, Mike.

MR. LEAON: Okay, thank you, Commissioners. I do have a brief presentation on background for today's workshop. And first let me say I was remiss in not mentioning that we have Dave Hawkins from Cal-ISO who will be sharing a perspective from -- Cal-ISO's perspective on feed-in tariffs today. And we'll hear from Dave before lunch, or right after lunch. I apologize.

Okay, what I'll be talking about briefly in my background presentation is the direction from the 2000 (sic) IEPR. I want to talk a little bit about our goals for today. Also summarize

some of the feedback we have from the June 30 workshop.

Also spend some time reviewing the policy drivers that helped guide us in developing the policy paths that are identified in the report that's the subject of today's workshop. And briefly summarize those policy paths. And summarize our conclusions to date. And we'll be hearing from Bob Grace on those policy paths who will go into detail on those options.

First, from the 2000 (sic) IEPR there are two key recommendations. One was that the CPUC immediately implement a feed-in tariff for all RPS eligible renewables up to 20 megawatts. And that this tariff would initially be set on the MPR. And we'll be hearing from CPUC Staff today on their progress with that proceeding.

Another key recommendation was that the Energy Commission and CPUC collaborate to develop feed-in tariffs for larger projects over 20 megawatts. And we have been working with the CPUC through the stakeholder process on that recommendation.

Workshop goals. Before I talk about our goal for the workshop today, I'd first like to

thank our KEMA team and renewable energy office staff, and in particular, Drake Johnson, to my left, the Project Manager, for their hard work in putting together this excellent report, and in organizing this workshop.

Also like to thank CPUC Staff and Cal-ISO Staff for their willingness to be presenters today. And finally, I'd like to thank our panel members for their participation in the workshop. I think we have an excellent panel that will provide for a very informative dialogue about feed-in tariffs this afternoon.

In regard for our goal for today, through the panel discussion and stakeholder feedback we hope to identify which feed-in tariff policy paths make most sense for California.

An expanded feed-in tariff for California would offer a second financing strategy for renewable energy developers in addition to the existing renewable portfolio standard, or RPS, competitive solicitation. This additional funding approach offers another tool for achieving the state's renewable energy objective of 33 percent by 2020.

If the state were on track to meet the

RPS renewable energy objectives we might not find ourselves here today discussing feed-in tariffs. However, the reality of the situation is that since we're not on track to meet those objectives, and since the state's renewable energy objectives are crucial for meeting not only greenhouse gas reduction goals, but also to reduce risk to ratepayers who continue reliance on fossil fuels, it is prudent that we're here today to discuss policy options for an expanded feed-in tariff.

The draft whitepaper, California Feed-in Tariff Design and Policy Options, forms the basis for today's workshop. The draft whitepaper lays out six policy paths for implementing a feed-in tariff in California.

As demonstrated in Europe, the advantage of a feed-in tariff is its transparency through the establishment of a guaranteed price, buyer and long-term revenue stream. Because feed-in tariffs can reduce the cost and complexity of the contracting process and guarantees a price, developers are better able to secure necessary project funding.

In summary, an expanded feed-in tariff could add another arrow in California's quiver to

establish a diverse mix of sustainable renewable resources.

I look forward to hearing the views of our panelists, stakeholders and, of course, our Energy Commission and PUC Commissioners regarding the representative policy paths contained in the report today. And, again, our goal is to identify which of those policy paths makes the most sense for California.

In regard to the June 30 workshop briefly I'll go over a few of the themes and the feedback that we got from that workshop for an expanded feed-in tariff in California.

Those that were in opposition to an expanded feed-in tariff cited that the existing solicitation was working and there was really no need to fix something that wasn't broken.

Also, there was a concern that an expanded feed-in tariff would conflict with the existing RPS solicitation. In addition, they felt that we needed more experience with the existing program for wastewater facilities up to 1.5 megawatts before we attempted to expand the feed-in tariff beyond that existing program.

Also, many stakeholders commented that a

feed-in tariff may not address other key barriers related to transmission and permitting and siting.

Those that were supportive of the tariff again cited that the state's not on track to meet its RPS objectives. And also felt that the place to start with was under 20 megawatts, as this would help smaller projects obtain financing that they're not currently able to obtain through the existing solicitation. And this would be effective in increasing renewable energy generation in California, as was demonstrated that was also effective in Europe.

Continuing with the June 30 workshop results, there were some concerns about costs of a feed-in tariff. Specifically some stakeholders felt that the feed-in tariff is not market-based. And as a result, wouldn't be bid through a competitive process. And this would lead to increased ratepayer costs. And that also, since the price was guaranteed, that this would stifle innovation.

Stakeholders that saw benefits for a feed-in tariff cited that, again, based on the European experience it could be highly effective in increasing distributed generation, would reduce

contracting costs. And this would better enable developers to secure financing.

In addition, many stakeholders felt that a feed-in tariff might lower costs over time by increasing the mix of renewable resources in the system, and this would help to insulate against increases in fossil fuel prices.

In regard to the question of should a feed-in tariff replace the MPR, there were different opinions on this. Some felt strongly that any feed-in tariff should not be based on -- well, should be based on the MPR. And that a tariff -- others felt that a tariff should be cost- or value-based and independent of the MPR.

Also we had feedback that developers should be allowed to participate in either process, and that they would not necessarily be in conflict with one another. And it was up to the project developer to decide which process would best meet its needs.

Moving on to the tariff policy drivers. Based on direction from the IEPR and feedback from stakeholders, six feed-in tariff policy drivers were developed in the report. And I want to emphasize that these policy drivers should only be

viewed in the context of a feed-in tariff and that there's no broader application of these policy drivers. And that's an important point that I want to emphasize today.

The drivers included quantity, financial security, which were given high priority; diversity A, which is essentially all in; sustainable renewable energy; price stabilization and diversity B, focused on biomass.

I'll briefly go over the rationale for these priority drivers. For the high-priority drivers quantity the rationale there was increase the pace of development of renewable energy to meet RPS objectives.

And financial security. Provide increased market certainty and financial security to help developers bring new projects online. These were given the highest priority because if we can accomplish those two things, then we're going to get more projects in the ground.

Rationale for the medium-priority drivers. Diversity A, promote a diverse mix of renewable energy resources. A diverse mix of resources will help to increase system reliability and meet desired operational characteristics,

sustainable renewable energy, develop a self-sustaining renewable energy industry was the thought here.

Rates could be designed to increase market penetration and could also be designed to be ratcheted down over time as facilities become able to compete effectively in the market.

For the low-priority -- or, I'm sorry, we're still on medium. Price stabilization. The thought here was to help stabilize the cost of generation. The cost of generation can be insulated from fluctuations in the price, financial -- by creating a diverse mix of resources.

And finally, for diversity B, which was given a lower priority -- and, again, I want to emphasize that's in relation to a feed-in tariff and doesn't reflect a broader policy view -- the IEPR encourages sustainable use of biomass by investor-owned utilities. It would also be consistent with the Governor's executive order supporting biomass as part of the RPS. And energy derived from biomass technologies would also help to increase system mix and reliability.

Regarding the development of the policy

paths in the report, these paths were developed based on feedback from the June 30 workshop. And the policy paths reflect a range of options not limited to just over 20 megawatts. They include options from pilot scale to full market implementation.

And this was reflective of stakeholder feedback that we should take a go-slow approach, gain more experience with feed-in tariffs before we jump into the over-20 megawatt project size.

Again, these are representative policy paths. Others are possible. The paths are not mutually exclusive. And we included one scenario depicting possible policy path interaction and other interactions are possible.

And we will have a detailed discussion of policy paths in our upcoming KEMA team's presentation.

So, our conclusions to date. The state is not on track to meet RPS objectives. Existing RPS solicitation experiencing a high rate of contract failure. Increase renewable energy needed to help attain mandatory greenhouse gas reductions. Must reduce emissions to 1990 levels by 2020. And renewable energy will be a key

component of that.

Increased renewable energy will help reduce California's dependence on fossil fuels. Feed-in tariffs have been successful in increasing quantity of renewable energy in Europe. And we'll hear from Wilson about the European experience. And an expanded feed-in tariff for California could work in parallel with the existing RPS solicitation.

And finally, an expanded feed-in tariff offers the potential to have an additional funding mechanism for renewable energy developers that will help California meet its RPS objectives.

Again, so our goal today will be to look at those policy paths and discuss what makes most sense for California.

That concludes my presentation. I'd be happy to answer any questions.

CHAIRPERSON PFANNENSTIEL: Mike, let me just go to the discussion of comments from the prior workshop. They're sort of all across the board, obviously. But since most of the people, if not say all of them, the responders, are coming from a specific area of interest, self interest, did you divide them up into, say, what the

utilities said, and what the renewable developers said, and what the environmental groups said? So do we have a sense of where those comments fit?

MR. LEAON: Yes, definitely. And thank you for that question. Clearly, the IOUs came down on the side that we don't need a feed-in tariff. And that the existing solicitation is working.

The renewable developers were clearly in favor of a feed-in tariff, decoupled from the MPR, beginning, or up to 20 megawatts. And that's really how it divided out.

CHAIRPERSON PFANNENSTIEL: And is that true across the entire renewables community?

MR. LEAON: Well, I don't know if I want to say entirely --

CHAIRPERSON PFANNENSTIEL: Is there -- is there a lot of --

MR. LEAON: -- but, --

CHAIRPERSON PFANNENSTIEL: -- variation there?

MR. LEAON: -- I think we may have had one comment from a renewable developer that was not in support. But it was just the one.

CHAIRPERSON PFANNENSTIEL: Thank you.

COMMISSIONER BYRON: Commissioners, I attended a rather informal meeting over at the Legislature yesterday. Two or three members were interested in this issue of procurement, as well, with regard to renewables.

And, of course, I was mistaken. I thought I could, as a Commissioner, hide in the back of the room and not be noticed. But that wasn't the case.

And I was struck by the same sort of thing that I'm struck by your presentation, Mr. Leaon, is that we tend to frame everything in the context of the investor-owned utilities. And that entire discussion yesterday for three hours was all framed in the context of how this works in a regulated investor-owned utility environment.

And I think we have to think beyond that. Clearly everything I've been reading here indicates that we've got to figure out a solution. So I hope today that we'll think beyond just the regulation of utilities and what's in their best interest.

So, thank you.

COMMISSIONER DOUGLAS: Thank you very much. I don't have any questions, but I think at

this point if there are other questions from the audience specific to this presentation? Does not look like it. So, let's move on, then.

MR. LEAON: All right, thank you. Okay, I would like to introduce Wilson Rickerson with Rickerson Energy Systems. And Wilson's going to share information on the European experience with feed-in tariffs.

MR. RICKERSON: Good morning, everyone. Nice to be back here again. Everyone hearing? My levels okay on this thing? Okay, great.

We are going to take a quick spin through Europe and talk about some of the best practices that we've seen over there. We did talk a little bit about that in the last couple workshops. At a higher level we're going to dig more specifically about the design details of two specific cases, mainly Germany and Spain.

So, why do we care about Europe? First of all, we care about it because specifically the 2007, as Mike mentioned, IEPR directed the Commission to explore feed-in tariffs that incorporate features of the most successful European feed-in tariffs. So that raised the question, which ones have been successful, what

are the design features and so on and so forth.

Europe, in general, has been kind of a laboratory for renewable energy policy across the board for about the past 20 years. It's an interesting case study because certainly some countries are far ahead than -- made a lot more progress in meeting national goals than we have here in the United States.

Their policies have also been around for a long time. Portugal started its policy process in 1988. Germany in 1990. Spain in 1994. There's been a long and iterative process of experimentation, and they've tried just about everything. They switched from tendering and competitive bidding over to tradeable RECs. They switched from tradeable RECs over to feed-in tariffs. And so on and so forth.

There's a lot of lessons to be learned out there. But, you know, another question is, you know, which ones, which European nations actually have been leaders in terms of policy design.

When we talk about Europe we tend to think, oh, they all do feed-in tariffs. And that's, to a large extent, true. We've got 18

countries in the EU that have feed-in tariffs, and also recently the green countries you see, both in Europe and on the periphery of Europe, have also adopted feed-in tariffs in the last couple weeks, the last couple months.

But it's hard to point a finger, just like it's hard to say, this is, you know, we have one single RPS here in the United States, and the same rules apply across all 26 different RPS states. There's also not one good example of what a feed-in tariff is in Europe. Every single one of these feed-in tariffs is different in some aspects, actually dramatically different.

So we decided to focus in on, okay, which ones have actually moved the fastest and moved the farthest. As probably most people in the room know, those two are Germany and Spain.

They have been certainly the most successful in terms of increasing the share of their national renewable portfolio. And they've also both used feed-in tariffs, which are fairly similar. People tend to group them together.

I think we're going to go ahead and walk through a quick snapshot of what their markets have done and what they could potentially do.

We're going to talk about their policy evolution over time, start with their first laws and talk about design decisions they made as they kind of iteratively changed their policies. And we'll do a side-by-side comparison of design details.

Germany, as you can see on the right-hand side, those are growth curves for different technologies. And most of those growth curves are dramatically up.

With wind, the top right, I don't know if you can see the yellow curve. It's gone up even as the annual installations have declined. That's because Germany's market is actually saturated. There's not enough land to put wind turbines on anymore, so now they're looking offshore. And that development is lagging.

But they've reached 14.2 percent of their national portfolio comes from renewables by -- they reached that in 2007. Their goal was 12.5 percent by 2010. So they're three years ahead of schedule.

They also, when they started back in 1990 they were about at zero. Their revised target is now 25 to 30 percent by 2020. And they have a goal of about 40 percent by 2030. Just on

the electricity side.

They've got 22,000 megawatts of wind. The U.S. is starting to catch up with that. Again, because their market is saturated and they only did 1600 megawatts last year. They've got 3800 megawatts of PV, of which they installed 1000 megawatts last year, more than the entire historical installations in the United States in one year.

And also biogas, although it's been small, has grown significantly. They're up to about 1200 megawatts in total. But that figure doubled between 2005 and 2007 largely because of some tweaking they did to their feed-in tariffs specifically to target biogas. They have a diverse, large and growing portfolio.

So how did they get there? In early 1990 and into 1991 -- sir?

COMMISSIONER BYRON: If I may interrupt with just a quick observation. These numbers, Mr. Rickerson, that you put up are just extraordinary, the transformation that has taken place.

Can you just characterize -- you said the wind is saturated, they're running out of land essentially?

MR. RICKERSON: Yes.

COMMISSIONER BYRON: They're beginning to look offshore. And photovoltaic has in one year exceeded all the U.S. installations. How sunny is it in Germany?

MR. RICKERSON: That's a good question. They actually, their best resource starts where our resource kind of gets off the bus. They start around where Seattle and Alaska are and go down from there.

So I guess the punchline is this, their solar energy resource is much worse than ours, but they actually have achieved -- I think we talked about this briefly in the last workshop, but, you know, they're not just building sculpture over there, they're not just putting in PV panels and wind turbines that aren't doing anything. The 14.2 percent penetration figure shows they're actually generating electricity to go along with that.

COMMISSIONER BYRON: Wow. Well, clearly it shows, in my mind, that they've got the right incentives in place to make this work.

MR. RICKERSON: The European Union, you know, I think a lot of different ways of defining

success. The European Union has defined success as they've analyzed their policies as how have you exploited your locally available resource on a country-by-country basis. And also how has your price matched that generator's need to actually be financially viable.

And both Germany and Spain have ranked, more or less, near the top on those two success indicators.

COMMISSIONER BYRON: Thank you. I'm sorry for the interruption.

MR. RICKERSON: Please feel free. The policy evolution. They started in 1990 with something called a Stromeinspesingsgesetz, which is the electricity in-feeding wall. Which basically they guaranteed grid access to all generators. You could feed your electricity into the grid. That's where you get the term feed-in tariff.

It wasn't a fixed price, though. It was a price that changed every year -- well, actually changed with retail price. So they pegged the price that generators would get to the retail price. Somewhere between 65 to 90 percent of retail. And that was differentiated slightly by

generator.

So, wind and solar got 90 percent of the retail price. Biomass and hydro -- small biomass and hydro got 80 percent, and so on.

They also capped their program. You couldn't have a system larger than 5 megawatts. And you also couldn't have -- a single utility could not have more than 10 percent renewable energy penetration in their service territory.

Also costs were redistributed between each utility nationally. So if you had a lot of wind, like let's say the north of Germany, and you had a lot of wind tariffs, then those ratepayers would bear the cost of those tariffs.

Their market took off. They had one of the fastest growing markets in wind through most of the 1990s. It was kind of a race neck-and-neck between Germany and Denmark.

However, a few cons with the policy. It wasn't competitively neutral. Germany was going to start moving towards electricity liberalization, as they call it over there. And having costs being borne by one utility that weren't being borne by another was problematic.

Secondly, it didn't encourage emerging

technologies. Sure, it was a good policy for wind, but the 90 percent retail pay didn't really help solar very much. The only places where solar was growing was in municipal utilities where they were giving them cost-based feed-in tariffs. About $1 per kilowatt hour back in those days, in the early '90s.

And also because the price was fixed at a retail indicator which varied over time, when the retail price actually started to sag in Germany, the market sagged with it. And also generators that had invested with the hopes of getting a certain price over time were disappointed that it fell lower than what they expected.

So, through the '90s, at the end of the '90s Germany got a new government and they decided to overhaul the feed-in tariff, and they created the equally easy to say, Erneuebare-Energie-Gesetz, in 2000, which like most feed-in tariffs we think of, unlike the Stromeinspesingsgesetz, which was value-based and pegged to retail, it was actually generation-cost based. Which means you look at each technology and you try to figure out what that technology needs to be profitable and

you set that price.

The generators received 20-year fixed price payments. The payments were differentiated not only by technology, but also by size. So large, fuel-based PV systems got a much lower payment than small rooftop systems, for example.

And also for wind, they were differentiated by resource. So that if you had a very very windy area, it wouldn't be compensated quite as much as if you had a less windy area.

Finally, unlike the previous -- I'm sorry, not finally, excuse me. Unlike the previous law, there was no system size cap. Also no total generation cap. They just opened the market up. And they also nationally redistributed the costs instead of on a utility-by-utility basis.

For cost control they set schedules of price declines. Not so that if I invested in a project my price went down over time, but rather if I locked in in year one I got 20 years of the same fixed price. If I then locked in in year two, I got 20 years of a price that was maybe 5 percent lower than year one.

Kind of placing an incentive on getting

in early, but also putting downward pressure on prices over time. And in theory those schedules were based on experience curves of different technologies.

Since then they've changed the law two more times. In 2004 they adjusted their fixed price tariffs again to target new resources, different types of resources. Fine tune things so that, you know, size was better differentiated.

They also added fuel, differentiation for biomass, because they found that just a general biomass tariff wasn't getting your biogas and your wood and your other resources. They also added a tariff for facade-integrated PV, or BIPV, as we call it over here.

Then in 2008 they went in for another revision where they adjusted the feed-in tariff digression rates. Those are the rates by which feed-in tariffs decline over time.

For some resources they actually left them unchanged, or even raised them slightly. For wind, for example. And then for PV you saw 1100 megawatts went in last year. They thought they might have over-heated the market a bit, and so they increased the digression rates from about 5

percent to 6.5 percent, to more like 8 to 10 percent, every year. Got to bring those costs down further.

CHAIRPERSON PFANNENSTIEL: Excuse me. Are all of these changes, then, prospective, though. They don't affect the tariffs for customer renewable developers, producers already online, right?

MR. RICKERSON: Yeah, great question. It was just, if you've locked in, you've locked in. Again, one of their problems with the previous law was that it varied over time, and they wanted to have, create investor security. That's the way they saw it to do it.

COMMISSIONER BYRON: If I may also ask, you know, the differentiation that you discuss is based on technology, size and the resource type. Did you investigate -- perhaps you're not the right person to ask, I apologize, but why didn't they base it on, you know, the attributes of the electrons that were being generated, for instance, if they were dispatchable, or higher level of reliability, or time of day that they were being generated? The kind of characteristics that increase their value? Do you know why?

MR. RICKERSON: I think they wanted to keep things fairly simple at the beginning. And they wanted the markets to grow, and they knew they wanted all those technologies to grow, because part of their goal was market capture for specific, you know, industrial policy as well as energy policy. They wanted German manufacturers building PV, for example.

And so I think they just set the rates and let them go. I think that certainly other feed-in tariff laws, Portugal's for example, they have tried to build up to value-based, you know, levels.

But, again, the Germans wanted PV, and there's only a certain amount you can do with value over time. You can add maybe a CO2 adder or a grid adder or a location adder, as the Portuguese do, but maybe you don't get to that level to actually grow the PV market. And if your policy objective is to grow the PV market, then those obviously have to match up.

COMMISSIONER BYRON: Good answer, thank you.

MR. RICKERSON: On to Spain. Again, we've seen very rapid market growth. Last year

they set a European record for a single year wind. Additions were 3500 megawatts. They also have 500 megawatts of PV, also pretty impressive number, most of which actually came last year. 350 megawatts came online in 2007. And we'll talk a little bit about what some of the implications are of that.

Also, unlike Germany, Spain has a feed-in tariff for solar thermal electricity, or at least they had one from the get-go. While Germany, I think, is now considering one.

They've got a couple experimental plants online, but they've also got 270 megawatts of concentrating solar thermal electric under development as of, I guess, March of this year, I think with even more in the pipeline currently. And the rates are set such that it also encourages solar thermal storage. So we're seeing some interesting stuff with storage going on over in Spain, as well.

Unlike in Germany, the Spanish markets have not seen much biomass or biomass growth. I don't think either market, Germany or Spain, has seen much hydropower growth as a result of their feed-in tariffs.

But, again, impressive growth for a country that hadn't previously had large renewable energy markets.

So, how did they get there? They put the first foundations in place in 1994. They didn't really start in with full-scale feed-in tariffs until 1998. And they set up a law that now looks somewhat like Germany's. You can choose a feed-in tariff option where you get a fixed rate. Where the big difference in the Spanish -- whereas you can also choose a fixed premium that arrives on top of wholesale prices.

So, for example, it's kind of like our production tax credit for wind. You sell in the market for your electricity, and then you get 2 cents on top of the wholesale power price. Similar approach.

The costs are nationally distributed, but also unlike Germany's generators over 10 megawatts, had to forecast generation 30 hours in advance. In general, we see the Spanish have done more about grid interaction than the Germans have, in terms of their legal mechanisms.

The 2004 amendment, the Spanish again differentiated further, like the Germans did.

They set the contract, instead of 20 years, as the life of the system. Another difference from the German law, and I'll get to this in a second with a nice chart, it's kind of hard to explain without waving my hands all around, is that there is a fixed component that's based on generation cost in the Spanish feed-in tariff.

There's also a part that varies every year. Initially that variance was set by the government. They then moved on to setting it by retail price. And they've since moved on to pegging that small variation to the consumer price index.

Another important difference between the Spanish and German feed-in tariffs is that the German feed-in tariff is uncapped. The Spanish tariff isn't capped, but they have revision traders. You can see 13,000 megawatts for wind, 200 megawatts for solar thermal, 150 megawatts of PV. When you cross that boundary the government then huddles and says, okay, now what.

They also had an incentive in the 2004 amendment for generators to choose the fixed premium rather than the fixed tariff, because they wanted people to participate in the wholesale

electricity market.

The 2007 amendment, they then promptly removed that incentive because everyone had jumped into the premium, spot market prices had gone haywire, and all of a sudden they were paying everybody a lot more than they thought they were going to pay people with that premium on top of market value.

They also established, just on the premium side again, a floor value for that premium and a ceiling for that premium, as well, to make sure again that it controlled costs.

Finally, let's move ahead to the 2008 amendment. This one they didn't necessarily see coming. It was triggered by this revision cap for PV. They had 150 megawatt ceiling. They got about 350 megawatts, so the government pulled back, put a moratorium on PV development and adjusted the rates. And as a result, rates, as most people in the PV industry are very aware of, at least investors in the PV industry, have lowered from about 44 cents a Euro, it's about 34 cents a Euro, a significant decline.

Again, very briefly. Spanish setup, how do the tariffs actually get built, I guess. This

is the fixed tariff side on this side. You got a generation cost based piece that doesn't change. You got a small part that varies on top. And the fixed piece is actually revised by the government every four years or so.

The feed-in premium, you got the market price that varies at the bottom. You got the fixed piece on top. And then you've got the variable part that varies with the consumer price index on top of that, with the floor and the ceiling.

Rushing a little bit because I'm getting close to the end of my time. But, if anyone has any particular questions about this structure, you can see me after class.

CHAIRPERSON PFANNENSTIEL: Yeah, well, let me just --

MR. RICKERSON: Yes.

CHAIRPERSON PFANNENSTIEL: I'm sorry, well, class is still going on.

MR. RICKERSON: Go ahead.

CHAIRPERSON PFANNENSTIEL: The part of this that is revised by the government --

MR. RICKERSON: Yes.

CHAIRPERSON PFANNENSTIEL: -- or set by

the government administratively, the concept overall is to provide cost plus a return to the renewable developers, yes. And then the amount of return, perhaps, is revised or re-examined over time?

MR. RICKERSON: That's correct. And, you know, the Germans just fixed one price and they shoot for about 5 to 7 percent returns. And they kind of monitor that over time.

And as you can see with the Spanish, it's more complicated. And so it's, I think, probably a little bit harder to gauge. But that, in theory anyway, is what they're trying to do.

CHAIRPERSON PFANNENSTIEL: Okay. So they're not trying to track the market at all? This is for the cost and the return for a specific renewable developer?

MR. RICKERSON: Yes. That's correct. Under both Germany and Spain that's ultimately the theories, investor security and generation cost base, which means you're targeting specific generation types with rates they need.

MR. TUTT: And, Wilson?

MR. RICKERSON: Yes.

MR. TUTT: One last question there. If,

under the Spanish premium system, if that brown bar at the bottom, the wholesale market price, goes up significantly, as it has sometimes, --

MR. RICKERSON: Yes.

MR. TUTT: -- the green disappears, the government doesn't pay anything?

MR. RICKERSON: No. Those two blue bars, it was kind of hard to put together, that's the floor and the ceiling of the total value the generator can get. So, if the market price goes through the roof, then the most you could get was that of market price plus the fixed piece plus the slightly variable piece. That total bar could only hit the ceiling. Can't go beyond that.

MR. TUTT: So if the brown goes above the ceiling, what happens?

MR. RICKERSON: If the brown goes above the ceiling, you just get the brown.

MR. TUTT: Thank you.

MR. RICKERSON: Sure. So, kind of a side-by-side comparison. The yellow stuff is significantly different. The white stuff is stuff that's not all that different.

Germany contract length is 20 years and Spain it's the project life. The tariff structure

generally is a fixed payment in Spain; it's a fixed payment or the fixed premium. Both are based on generation costs, as Commissioner Pfannenstiel is asking.

Both are differentiated by technology and size. Spain does not differentiate by resource, i.e., wind. Germany does.

Tariff adjustments, I guess we just kind of walked through with that in that last slide. The Germans have a fixed schedule over time of declines. And they're advised once every four years.

The Spanish, it tends to vary, depending on what's going on in the market, which rates they're choosing. And also the government not only revises, but also the revisions can be triggered by these capacity thresholds. In Germany there are no caps at all. Again, in Spain, there are those triggers.

And then interestingly, the last three year Germany has no forecast obligation for generators. They have -- we didn't really get into this in the presentation, but there's no incentive for generators to provide more voltage support, for example. And there's also no peak

generation differentiation.

In Spain there is a forecast obligation. There is an incentive, actually, to provide voltage support, not a penalty. And there's a slight peak generation differentiation. You can get 96 percent of the rate offpeak and 104 percent of the rate onpeak if you so choose. I mean you have to choose it. You don't have to take that if you don't want to. Those are kind of the big pieces of the two.

In my last remaining minutes here, general lessons learned across these two countries, in any event.

Long-term generation cost based payments can rapidly grow or grown, renewable energy markets and achieve national targets. That's been clear from both Germany and Spain.

Technology-specific tariffs can create diversity when set at appropriate levels. Do you want a certain type of technology. Or do you want a certain type within a type of a technology. Do you want small biogas digesters powered by manure. And you want to set a tariff for that, you can probably get a market response.

Investor security, which has been a big

priority for both Germany and Spain, is determined both by price certainty and also policy certainty. The only reason I bring that up is because we saw that with the Spanish PV panic recently when the capacity triggers were reached. And people weren't sure what the rules were going to be, post-capacity trigger. That kind of policy uncertainty sent ripples through the market.

While as in Germany it tends to be more, you know, you've got your schedule of price declines fixed over time. You know kind of what the rules are, how they may change or may not change.

Value-based incentives or incentives tied to market price may not put downward pressure on renewable energy prices. In Spain the wholesale market premium could go continually up and up and up. That's why they put a cap on it. Whereas in Germany it got a declining price schedule that goes down over time theoretically putting downward pressure on prices.

Also, another good reason that Europe -- another reason Europe is interesting to look at is because they've done a lot of introspective and empirical analysis over the past 10 or 15 years.

And both Germany and Spain recently did policy cost studies at the federal level. And both concluded they've suppressed wholesale market prices by having these fixed price feed-in tariff contracts. And some studies have suggested that that suppression has been greater than the overall policy cost.

They both, on the technical side, they both distribute policy costs nationally. They both use long-term contracts.

Then kind of on the con side, or at least the challenge side, support for emerging resources kind of implementing. For example, PV feed-in tariffs has been difficult. Both Germany and Spain have had to pull back a little bit and reduce, sometimes significantly, the amount of payments.

And also in both markets setting the correct price for biomass has been challenging. Initially, biomass didn't respond to either of the feed-in tariffs. And after they did some tinkering, at least the German market has started to grow, as well, when they start differentiating by fuel, not just by biomass.

And the last thing, I saw it in Mike's

presentation, another lesson learned on the innovation side is that the Europeans have claimed that feed-in tariffs do create more innovation in other models. Largely because they shift competition from generator price to the manufacturers. It's actually manufacturers competing to supply efficient technology, to kind of get underneath that feed-in tariff.

And they've seen, you know, not only a lot of manufacturing develop in Europe, but also prices have come down in Europe. And also a lot of the wind turbine innovation we've now benefitted from, the United States, in our markets came from ten years of early feed-in tariffs in Denmark and Germany, where feed-in tariffs driving industrial innovation.

I think I'm almost even on time.

MR. LEAON: All right, thank you very much, Wilson. Questions --

CHAIRPERSON PFANNENSTIEL: Question.

MR. LEAON: -- from the dais?

CHAIRPERSON PFANNENSTIEL: Yes. And it's perhaps the hardest one. I'm just -- the conventional wisdom here is that Germany's had a lot of success in renewable development. And

Spain obviously is closing in on that. But, at an incredible price, retail price. And that their retail prices have been driven up unconscionably by this feed-in tariff.

What is the effect? I mean there must be some way of gauging how much this has affected the retail prices for electricity in Germany and Spain. What do you think?

MR. RICKERSON: It's .1 percent in Germany.

CHAIRPERSON PFANNENSTIEL: .1 percent higher than they would have been or --

MR. RICKERSON: I'm sorry, .1 percent of retail ratepayers' -- maybe about 20 cents per kilowatt hour there, and .1 percent of that is attributable to the feed-in tariff in Germany.

In terms of overall cost increase, they have done studies about that, as well, that project through 2030. And I can get you those. I think it's something like Euro.50 per household per month when prices peak in 2017. And then start declining as old contracts expire, but also as retail prices have risen in the interim.

I'm not sure for Spain.

CHAIRPERSON PFANNENSTIEL: And in Spain,

something comparable, or do you know?

MR. RICKERSON: I would imagine it would be comparable, but I don't have the figures. And also they recently set both those caps on the fixed premium.

CHAIRPERSON PFANNENSTIEL: Right.

MR. RICKERSON: And they also have pulled a weight incentive for the fixed premium. And so I think a lot of that was driven by policy cost concerns, as was the PV growth. So they haven't had huge impacts. I think it's on their --

CHAIRPERSON PFANNENSTIEL: And then, obviously this discussion is all about the tariff part of it. But there's also, of course, the system integration questions --

MR. RICKERSON: Yeah.

CHAIRPERSON PFANNENSTIEL: -- and these kinds of levels of renewables. Has that been something that has been then fed back into the feed-in tariff?

MR. RICKERSON: You mean in terms of the rate, itself?

CHAIRPERSON PFANNENSTIEL: Yeah, the question of, you know, having too much wind in a

geographic area for the system, the rest of the electrical system to support it there. Have they changed prices according to that, those kinds of considerations?

MR. RICKERSON: I guess a couple different answers there. Clearly the Europeans, in general, have pushed the envelope on how much renewable energy you can feed into the grid. You know, Denmark is way above where we thought people could actually be.

And so in some ways they've redefined what we thought was possible. On the other hand, there are probably people much better than I am on this that could answer the integration questions more directly.

I think from a cost perspective, integration cost perspective, German (inaudible) has done that comparison of kind of integration costs, administrative costs and incremental cost to the feed-in tariff versus wholesale price suppression, savings from imported coal and oil.

And in those kind of side-by-sides that's where that study came from that they'd actually saved over all in at least 2006 over the policy costs, itself.

CHAIRPERSON PFANNENSTIEL: Thank you very much.

COMMISSIONER BYRON: If I may, one quick question. And this really is the same question Chairman Pfannenstiel raised. I just want to make sure I understood it clearly, because I don't think it was in the report.

You're saying that the financial impact, the cost impact of this FIT in Germany has only been .1 percent on rates?

MR. RICKERSON: I think I might be answering it in a different way than you're asking.

COMMISSIONER BYRON: Please ask the question correctly, the --

MR. RICKERSON: If I'm looking at a pie of German retail rates and saying, this slice is attributable to this, this slice is, you know, this is transmission, this is distribution, this generation, you know, it's 20 percent, 30 percent, what-have-you. Then .1 percent of that pie slice or .1 percent of that pie is the part attributable to feed-in tariffs.

COMMISSIONER BYRON: I don't recall seeing that in the KEMA report. Is that in there?

MR. RICKERSON: It's not. It's from a -- there's an English language version available from the German Federal Government that I can send you.

COMMISSIONER BYRON: Well, you know, this is the key argument that the investor-owned utilities raised, that the FIT is not market based and would increase ratepayer costs. But clearly the benefit here would greatly outweigh a .1 percent increase to customers.

MR. RICKERSON: The Germans have definitely made that argument.

COMMISSIONER BYRON: Seems to me you speak German pretty well, is that correct?

MR. RICKERSON: I used to.

(Laughter.)

COMMISSIONER BYRON: All right, then I won't put you on the spot.

MR. RICKERSON: Okay.

MR. KINOSIAN: Given the large amount of resource development, have they run into, in Germany or Spain, transmission constraint problems? And if so, how did they deal with them?

MR. RICKERSON: Again, that's a good question, and I'm not entirely sure. Generally,

Germany is a denser, more populous country with a denser transmission system than the United States is. So we probably have concerns that they don't.

MR. TUTT: I just wanted to follow up a little bit further on the cost question. Given the low numbers you're describing here, you'd almost think there'd be no opposition. Has there been opposition in terms of a cost-based opposition in Germany and Spain to these feed-in tariff policies?

MR. RICKERSON: There's been the start of it. I think mostly it'll focus on the PV side in both Germany and Spain. I think in general the nearer market resources people are fairly happy with, because that's where most of the wholesale price suppression comes from. And kind of more the emerging technologies, which they argue -- well actually the benefit from all this, the near-market stuff is going to blend in the PV costs. But they're still now trying to walk a fine line as to what extent do we really want to blend in those higher PV costs.

And we've seen them, you know, as we said, in the past six months both countries take a step back.

MR. TUTT: Right. In fact, in Germany they've made a significant change in their declining rate structure for PV.

MR. RICKERSON: Correct.

MR. TUTT: Green Power Institute, in comments on our previous workshop, said that all the successful feed-in tariffs in Europe are at a healthy premium above the market prices. Is that a true statement, do you believe?

MR. RICKERSON: It depends on where, you know, -- not all the time, no. I mean if you look at German spot market prices some of their feed-in tariff rates are below the spot market prices.

You also have a choice of what you can sell in Germany. You can sell in the spot market, you can sell in the feed-in tariff, or you can offset your own native load. And people make different choices depending on what the feed-in tariff is versus what their other choices are -- options, excuse me.

COMMISSIONER DOUGLAS: Very good. I think that's it for questions from the dais. Are there questions from the audience specific to this presentation?

Very good.

MR. LEAON: We did have one question from a WebEx participant. Tobin Richardson has a question for Wilson regarding an announcement last week in Spain. Increasing the cap to 500 megawatts for solar. Let me ask Joe if he can further translate for me, I apologize.

MR. FLESHMAN: The question was if Wilson could please comment on the announcement last week in Spain on increasing the cap on solar in 2009 to 500 megawatts with a reduction of the tariff available. And what the rationale and implications for the program would be.

MR. RICKERSON: The short of it is that it's bad, but it's not as bad as everyone thought it was going to be, from a PV market perspective. I think when the capacity trigger first occurred, kind of a hush settled over the Spanish industry trying to figure out which direction they were going to move in. And the initial reports were the prices were going to come down maybe 50, 65 percent, and that the caps were going to be -- they were going to institute a year cap, a one-year cap of 300 megawatts. You couldn't do more than 300 megawatts in a single year.

That's since gone up to -- the final law

came out three days, two days ago, three days ago, I'm not sure exactly when. It's 500 a year of which 100 megawatts is just for ground-mounted systems. And the prices are not as low as everyone thought.

And in terms of market commentary I think I'll leave that to the market commentators.

MR. TUTT: Wilson, one last question on that, if you would. You said that the Spanish feed-in tariff for PV had gone down to .34 Euros --

MR. RICKERSON: Yeah.

MR. TUTT: -- per kilowatt hour. Any idea what that is in our money?

MR. RICKERSON: Like $1000 I think --

(Laughter.)

MR. RICKERSON: With current exchange rates, --

(Parties speaking simultaneously.)

MR. RICKERSON: So it's very generous. No, actually, I'm not -- it's 1.4. Okay.

MR. TUTT: Okay. Thank you.

MR. LEAON: We have one speaker in the room here. Do you have a blue card?

MR. MATTESON: No. I'll get one to you.

MR. LEAON: Okay. Okay, if you'd go ahead and state your name and organization for the record.

MR. MATTESON: Gary Matteson, Matteson and Associates. I'm interested in the comments you made about Germany reaching capacity in wind in a couple places. And it seems like they've reached that capacity in a bit of a surprise. Could you comment on that?

And could you also indicate whether either country has made any effort to determine what their resource availability was, and especially with respect to Spain and the biogas. Had they made an estimate of how much biogas they could gain out of the various resource streams? And what percentage of that was achieved?

MR. RICKERSON: I guess I'll take the first question which was wind and capacity. Just to define the capacity is more kind of available onsite resource. Again, the Germans define it differently because they have incentives for wind resources that we might not otherwise incentivize over here, just because the wind resource is less across the country. You know, some 15 percent capacity factor some places.

And in terms of it being a surprise, I was working for the German Wind Energy Association back in 2001 and their graphs, you know, show onland capacity peaking and then descending because of kind of saturation.

Then they saw their future domestically being repowering. And then offshore wind, both spiking. And then export markets. And I think the repowering and offshore wind haven't happened as quickly as they would have liked, and so now they're really hoping the export markets pull through. And so far, they seem to be.

In terms of the biogas side, the Spanish I don't think have done much with biogas. It's been the Germans that have been pushing for biogas. I think it all depends on -- I'm sorry to answer on this one, as well, but how you define biogas resource.

The Germans, their feed-in tariffs for biogas have been set to give a premium for agricultural waste and manure. And that's actually allowed farmers to grow corn solids specifically to be dumped into biogas digesters in order to get the feed-in tariff rate.

So, if you're looking at biogas that

way, growing stuff, growing feedstocks specifically for biogas, rather than just waste, that's, you know, can significantly expand your available resource.

MR. LEAON: Okay, thank you, Wilson. I have a couple more speaking requests, but we'll take one more question. We are behind time, and Wilson will be available this afternoon and we can take further questions on this topic during the open discussion period of the workshop.

So, one more question on this, and then we do need to move on and we'll probably have to take some time out of our lunch.

Next question was from Pete Gregon, President, Advanced Solar, Hydro Power.

MR. GREGSON: Thank you very much, Commissioners. My question would be Europe and Spain, are the utility companies installing these systems? And what percentage, what megawatt?

A perfect example would be that the utility companies in California are obviously big players in this. And especially in my area, they are starting to tell my customers don't install solar because we will. Thank you.

COMMISSIONER BYRON: I'm sorry, they're

beginning to tell your customers what? I'm afraid we couldn't hear you up here.

MR. GREGSON: Don't install solar because in a few years we will.

MR. TUTT: Can you state your name and affiliation for the record, too, please?

MR. GREGSON: Pete Gregson, Advanced Solar, Hydro, Wind Power Company.

COMMISSIONER BYRON: Thanks, Mr. Gregson.

MR. GREGSON: Thank you.

MR. RICKERSON: If the question's about -- I guess it's a utility ownership, maybe? Is --

MR. GREGSON: Are the utility companies basically competing with private firms? Are they installing solar and wind and hydro systems like we are in California? And is that -- basically what I'm getting at is that part of their incentives or not?

In this country --

CHAIRPERSON PFANNENSTIEL: Sir, none of this can be heard by people --

MR. RICKERSON: I think I got you, Mr. Gregson.

MR. GREGSON: So basically I'm trying to figure out the relationship of the European market compared to us, and what the complication is with their utility companies versus our utility companies.

MR. RICKERSON: Yeah, I think it's worth a closer look. I know that in -- I don't think they're doing a lot of -- utilities doing a lot of installation, they're getting to that part of the value chain over there.

I know in Spain they're doing ownership, but not so much in Germany, at least not initially. But in Spain a large portion has been utility owned.

MR. GREGSON: And so they go out and buy, hire private installers to install it and they own the system?

MR. RICKERSON: Yes.

MR. GREGSON: Okay. Do you know what percentage, what megawatt?

MR. RICKERSON: I wouldn't want to go on the record with that.

MR. GREGSON: Anywhere we can find that?

MR. RICKERSON: Maybe the German Solar Energy Initiative Association.

MR. GREGSON: Okay.

MR. RICKERSON: They actually have -- yeah, very knowledgeable of that sort of stuff.

MR. GREGSON: Great, thank you.

COMMISSIONER BYRON: Good question.

COMMISSIONER DOUGLAS: Before we go on I'll interrupt by saying that unfortunately I've been getting and ignoring calls from my daughter's daycare during the last presentation. I finally went out in the hall and listened to it, and she is apparently sick and apparently they're afraid she's contagious. So, --

COMMISSIONER BYRON: So they need to --

COMMISSIONER DOUGLAS: They need me. So, I'm going to be a WebEx participant to the extent possible. But I'm afraid I'll have to leave for now and leave this to my fellow Commissioners and to Chairman Pfannenstiel, in particular, who is our remaining representative of the Renewables Committee present today. Thank you.

CHAIRPERSON PFANNENSTIEL: So, let's continue.

MR. LEAON: All right, thank you, Wilson. Our next speaker is Bob Grace with

Sustainable Energy Advantage. And Bob will be discussing policy options and interactions as contained in the California feed-in tariff design and policy options report.

COMMISSIONER BYRON: Before Mr. Grace begins I know that we're a little bit behind schedule, but that last presentation was very good. And I know I don't mind if we're behind schedule and that you're taking away part of my lunch.

MR. LEAON: Thank you, Commissioner.

MR. GRACE: Good morning. Everybody hear me okay?

Well, we can clearly learn a lot from the European experience. But it's also equally important to think about how to apply that in our context here in California.

Perhaps it's an understatement that California has perhaps the most complex renewable energy policy landscape in the country. Layered on top of that we have things like federal production tax credit, investment tax credit, expiration uncertainty, which creates a big barrier to projects moving forward.

So, clearly, introducing into that mix

the concept of an expanded feed-in tariff can and has elicited a wide range of reactions which may or may not be applicable or appropriate depending on the specifics of the policy that you are looking to implement.

We had started off this process leading up to the first workshop in creating the issues options paper, really breaking down the building blocks of feed-in tariffs, and hopefully giving stakeholders and the Commission and all the representatives here an opportunity to understand the details and have the same language and tools to work with.

And so the question was where do we go from here. There are a lot of details to be worked through. And we had prophesied that distilling some of the essential or core elements of those details into some distinct policy options would give us the opportunity to leapfrog the dialogue and it started to get a lot more specific.

So, for those of you who have been supportive of feed-in tariffs in general, here's an opportunity not just to say yes we like them, but to be responsive to well, what do you like,

which one and how.

And for those of you who have generally been resistant to feed-in tariffs expressed discomfort, well, this is your lucky day because we've laid out multiple options, maybe multiple softballs for you to take a swing at.

But, in doing so, we're going to ask not just to say no, but to get specific and say, in relation to a specific proposal, why, what's wrong, what might not work. And to take it a step further, well, how can we change it and make it work so that we can have a productive dialogue that we can all build on here. And that's the approach that we've taken in getting to this point.

So the purpose of my talk is to introduce the outlines of a range of the potential future feed-in tariff policy alternatives as a basis for further discussion. Touch briefly on the policy drivers and how they took us here. And then get to the policy issues and options and how they led us to representative policy paths.

I'll also talk about interactions among those policy paths, maybe thinking of them as policy trajectories. They're components that one

might look at as either transitions from one to another or things that one can do at the same time or not. And then wrap up with next steps, which will lead us to this afternoon's discussion.

So, as far as the policy drivers go, as Mike mentioned earlier, we really started with the broadest of goals, reducing greenhouse gas, reducing fossil fuel usage, managing ratepayer costs and risk. That really translates into the broad renewable energy policy objectives, the 20 percent renewables by 2010, the 33 percent by 2020. And that led to the development of these policy drivers that Mike discussed already.

All of these things need to be considered, of course, within the -- subject to constraints, the practical constraints. Available transmission; siting and permitting; the feasible buildout, how much resources that are out there; as well as cost effectiveness and environmental resource sustainability. So that's the lay of the land in which to consider everything. And in which we've started considering these in developing policy options.

So, this is a busy graph. I'm not going to ask you to focus on the details here. I'm just

bringing this back to the issues and options report from a few months ago where we laid out, there are a lot of pieces, a lot of decisions to be made, a lot of issues in developing a fully fleshed out feed-in tariff. Enough that they fit onto two slides.

(Laughter.)

MR. GRACE: So, to try to wrestle all those details into something that we could take to the next level of discussion we decided to break it down a little bit.

The issues and options report identified a range of the design issues and options. There are lots of possible combinations of all those things I just flashed through on the screen.

We sorted them, the team sorted them into three categories. One was the core policy issues. Those are really what we consider the high-level policy decisions that dictate the feed-in tariff strategies. These may be the critical characteristics of alternative feed-in tariff policy paths. The things that really can mark the different forks in the road, different ways you could go in design.

Then there's another set of those design

issues which we grouped into noncore policy issues. Now, these may be fundamentally important and they would modify the specifics of the feed-in tariff design, but they don't fundamentally alter its core structure.

They definitely require decisions if one chooses to move forward in designing and implementing a feed-in tariff or one of the policy paths. But for the most degree they are independent of the policy paths that you select. And so they could be applied to any one of the selected policy paths. So, in order to move forward we set those noncore policy issues aside.

And then there's a third category which we labeled as implementation details. Other things that would need to be addressed, but they don't require major policy decisions. They're not ripe for discussion at this point in time in the development of this dialogue. And so further discussion of those can be deferred.

So the core design issues, what are they. Well, -- and how did we get there. We narrowed the full range of decisions through considering a lot of different things. The policy drivers, the input of the Energy Commission's

Renewables Committee, the pros and cons that were laid out both in the issues and options report, as well as those which were relayed through stakeholder comments.

We took into account the practical constraints in California precedents. We do have to fit these things into the structure that we already have in place here in California.

And then through our own, the Energy Commission Staff and consulting team analysis. And we went through all those things. We found that there were some issues which really only had a single viable choice when you consider all these other constraints. We can already decide really what the viable path is there.

But the remaining issues we used to craft a representative range of policy paths. Now you're going to keep hearing me use the word representative; I'll try not to be too redundant about it, but I think the key point here is we're creating a set of strawmen here. There's nothing magic about them, other than that they will parse out some very distinctive futures.

And I think we're hoping that the dialogue here can allow us to be open to other

policy paths that might be some combination of those we see here, or some slight modification.

So, when you put something specific out there, you usually can get feedback, and then it can be, you know, negative feedback. But we're trying to make it into positive feedback.

We're not standing firmly behind any of these. They are there as representatives to enhance the dialogue.

So, what are they? First of all, what is a policy path. We consider this really to be a high-level strawman outlined with feed-in tariff option. It would characterize fundamentally distinct policy design alternatives.

And, again, it's constructed from those options from the core design issues. We consider this a more fruitful approach than considering all the possible combinations and options. And this is intended to stimulate a dialogue.

So we came up with six of these. They are representative of a wide range of different futures. They span the range of direction of scope, meaning where you might apply them. Of timing, when you might apply them. So they are forks in the road. Yet there are also

interactions leading to possible implementation trajectories.

And, of course, there's the implicit second choice, which is maintaining the status quo and not implementing any further feed-in tariffs than are already being put into play.

I'm going to throw up here two slides which give you the 50,000-foot perspective of these policy paths, and then go into each one in more detail.

These vary, the characteristics on the left-hand side here are those core characteristics that we considered as differentiating characteristics.

So, resource type. What resources do these feed-in tariffs apply to. Vintage, is for new, repowering or more broadly size, that's a very important one, given the dialogue to date for everything, or above and below certain threshold.

Scope, is it applying to the full market, just as a pilot, maybe a limited, maybe in just one utility. Is it happening just in a competitive renewable energy zone.

Setting the price, how do you go about setting the price. Are we looking at cost-based

or are we looking at value-based. Are we looking at using a competitive benchmark process to set cost-based, but have some real market information to base that off of.

What would be the duration of the contracts, long-term, short-term, medium-term. How are these tariffs differentiated. Are they differentiated at all like today's MPR-based approach, which really isn't. Or are they more akin to the German and Spain approaches which have different prices for all kinds of different technologies and sizes and applications.

And finally, would there be limits. Would you be capping or not capping the quantity in total, the rate impact, or the quantity-specific technologies or tiers that might cause concern and rate impact or such.

So, I wanted to give you this big picture. Those are the differentiating characteristics. As we looked at this, there were some single option design choices which we consider would apply to all the paths.

And here, this includes the generator paying for interconnection. There wasn't any indication from our analysis and comments that

that should change in the California context. As well as upstream transmission being allocated more broadly across the transmission owner.

Having a fixe price tariff as opposed to one that floats seemed to be the universally supported, and in addition, that it would be the transmission distribution utility that would offer the tariff, as opposed to the generation service provider.

Just logically, if you're a generator hooking into a system, to have multiple possible parties offering that, offering a tariff, energy service companies, the utilities, POUs, other utilities. You know, it doesn't seem like we've got a workable system unless there's just a single set of tariffs available to a particular generator.

Then we have some other core characteristics here down at the bottom which didn't seem to group into these different forks in the road. But once you've decided which fork in the road you're going to take, you can then select from this menu of other characteristics to further design your feed-in tariff.

So those include the method of adjusting

the price. Do you do digression as well as describe where you're stepping down the price available over time to do new entrants. Do you have something indexed to the value. Do you have something inflation indexed. We don't have to decide that now, and that choice is really independent of the policy paths, as we define them.

Similarly, when to adjust the price. A periodic schedule, or when you've hit a certain capacity, block, trigger. Or some other hybrid. Again, those are important choices, but they don't really differentiate the forks in the road and the big policy choices that are appropriate for this level of discourse.

And finally, another price aspect, just how much to adjust the price. Do you use experience curves, do you use uniform steps. We've seen both of those used in both feed-in tariffs and other renewable energy policies. Both have had some success, both have had their limitations. Again, we can focus on that at the next stage. So we haven't spent time in looking at the specific choices among those options.

So, policy path number one is what we

might call the full German-style tariff. This is as close to the German approach as we can fit into the California context.

So, looking at the left-hand side table here, this would apply to all resources. It would apply to new generators. And you might have a separate price for repowering.

There would be no limit on size. But here's an important differentiating characteristic. At least this is being put forward. This would be set up as a policy condition, to be triggered in the future if an event occurred. And that event, at least for discussion purposes, is if the RPS failed to meet the 20 percent target, at least under contract, by 2010, then yo might decide, okay, we're going to start shifting to a feed-in tariff which we would put in place a couple years down the line. So that's a trigger event, giving the RPS some more time to see whether that, alone, does the trick.

As far as the scope, it would apply to the full market. Whether that means just IOUs or POUs, generally speaking not just one utility or another.

Setting the price. This would be cost-

based, much like the German model, with initial prices that might be differentiated by resource-type-specific auctions in order to not calculate from an administrative approach what a solar or wind project should cost, but actually bring some competitive market information into that. This is a tactic that hasn't really been used in this context before, so there would be some questions as to how to apply that. But, again, we put it out there for discussion.

The contracts would be long term. What does that mean. Fifteen, 20 years open to discussion. Generally the idea is long enough to give price certainty; long enough to amortize fixed costs over a substantially long enough period so that the per-kilowatt-hour price doesn't need to be that large.

Tariff differentiation. We would recommend in this model differentiation by technology and size. Very similar to what was done in Germany. And as far as limits, we thought, well, we'd be capped at the RPS target in terms of total quantity. And that one might consider putting some caps on the more expensive technologies as a way of addressing some of the

concerns about possible rate impact.

So, what are the pros and cons here. On the pro side, like Germany, we could expect that this might enhance and stimulate rapid market growth. Clearly it would be established to offer investor security. It would stimulate quite a bit of resource diversity, especially to the extent that it created prices for all different types of generators.

It would help to stabilize rates and have the potential for wholesale price suppression, as the Germans have observed and experienced.

Putting a cap on the emerging technologies would potentially limit the costs so that that couldn't get out of control. And a trigger mechanism provides an opportunity for the RPS to continue to perform. As we've heard there are a number of stakeholders who feel that that success is around the corner, or depending on other things. And that it's too early to draw that conclusion.

On the con side an approach like this has uncertain level of policy response. Until you lay it out there you don't know what you're going

to get. And because of that it has an uncertain impact and cost. That's the fundamental difference between this type of approach and an RPS with year-by-year targets.

The competitive benchmark approach is untested. So maybe that belongs in here, maybe it doesn't. There's some thinking to do about how one might implement that.

And ultimately doesn't address the technical barriers, the other things besides contracts and certainty that are barriers to renewables. And this can be said of all the options here, so I haven't repeated this on each slide, but this, alone, isn't going to get transmission built, for example. And it's not going to get neighbors of projects that might otherwise be opposed to a neighboring project to swing their vote, so to speak.

So, now I'll talk about policy path number two here. Wilson just labeled this MPR on steroids. The idea here would be that generators greater than 20 megawatts would be able to take an undifferentiated value-based MPR-like price. And then you might try this out as a three-year pilot within one utility. See how it works for larger

projects.

So, this, again would be open to all resources, new and repowering. The size would be above 20 megawatts, again seeing how this works for larger projects. The timing, it would be available now or once set up, and would be available for a three-year duration. Or projects coming online within that three years would be able to get the contracts. And so, in that sense, it's a pilot, limited time, say one utility.

How would price be set. In this model it would be value based. So there might be time of peak differentiation. You might have CO2 or other adders. But basically it would not be a function of the cost of different technologies. Technologies would have to compete head-to-head or effectively be able to -- this would encourage the most cost effective renewables similar to what we're experiencing today with the MPR structure, the RPS solicitations.

Contract duration. Again, long term, for the reasons I discussed earlier. There would not be tariff differentiation in this approach. And because it was a pilot, there really wouldn't be a necessity to limit it. So, again, just

another strawman to think about and stimulate some reaction to how this different approach might take.

So what are the pros here. Well, it would give us immediate implementation experience. And unlike the other one, which was policy cap number one, which was based on a trigger, this would be put into place promptly.

The pilot nature, itself, would control the cost impact. And ultimately this could help answer the question, demonstrate whether standard offers that price certainty makes renewable projects more viable, increase investor security, reduces barriers, reduces uncertainty.

I'm going to take a side step here to talk about something that's not in the paper that I was thinking about this morning. We're in an environment right now where there's tremendous uncertainty for production tax credits at the federal level.

And with that uncertainty, as many of you probably observed, there are a lot of projects that have stopped or slowed down their process. They've got a price out there that they don't know whether they can meet or not, because they have a

major cost component.

And so uncertainties like that, as well as like what's happening on Wall Street right now, too, same question with financing uncertainty. In that environment projects stop, slow down, wait for Congress to figure out what they're going to do next.

You know, if we have an approach which maybe doesn't fit in this particular model, but if it was a cost-based approach and you had a price with and without production tax credit, you can take away that reason to stop development progress. So that type of certainty can be potentially helpful.

This also gives us an opportunity to understand and demonstrate whether a feed-in tariff can, in fact, lower costs, development, transaction costs for generators, costs relating to timing, risk premium, cost of capital, a lot of the things that were talked about as possible factors that feed-in tariffs could create to bring the cost of renewables down. It would give us an opportunity to see whether that actually works.

On the con side, this type of an approach would be unlikely to promote resource

diversity. Like today's approach it's going to be most open and most successfully used by those that are most cost competitive.

It's unlikely, by itself, to achieve the quantity targets, partially because it's a pilot. it's still going to be difficult for long lead time projects to respond, particularly biomass projects or hydro projects which take more than three years to develop.

And it may not provide the hedge benefits associated with long-term contracts depending on how the MPR or the value basis is set. So that's just a different path to think about.

Let's turn our attention to policy path number three which we call CREZ-only. So this is a German-style differentiated cost-based tariff approach that would be limited to application only within a competitive renewable energy zone, and only for generation above 1.5 megawatts.

Here, again would be open to all resources and for new generation. The timing would be linked to the timing of committing to transmission investments. So, it might be automatically in the 2010, 2011 timeframe so that

projects could be developed in parallel with transmission that had been committed to.

The scope, again, would be CREZ only, setting the price cost-based, contracts long term, again. The tariff would be differentiated, particularly for wind, by size, to address scale economies. Geothermal, biomass again by size to reflect scale economies. Solar perhaps by technology.

The limits would be related. There would be limits and ultimately would be capped at the CREZ transmission level. So this is something different to think about, how might this interact with and help within the competitive renewable energy zone context.

So the pros here, this would encourage generation development as soon as possible after CREZ transmission was committed. It would take the possible two-step process where that we might face within the RPS context, that CREZ is committed and the generation still needs to compete within the RPS solicitation, off the table.

It would have the same benefits, in general, as policy path number one. The prices

could potentially be set lower because you're picking an area where there's particularly good resource, which is why we chose it in the first place.

And, again, it eliminates this multiple contingency facing the generators that they -- for both the transmission and the solicitation selection process.

On the con side, same cons as number one, related in terms of the uncertain response and cost. There is no cap here on emerging resources, but that could be mitigated by the way you set the prices and do the differentiation.

Because there would be a limited quantity, you will trigger speculative queuing issues, which we've experienced. People with less viable product have to rush to get in line because of the limits. How do you allocate that scarce space within that limit.

There are, as we talked about in the issues paper, there are definitely ways of mitigating that, but this would trigger needing to think about some of those details.

Policy path number four is a very different approach and this would focus on one

technology only. This one's a solar only. So this would apply to solar systems greater than 1 megawatt. Chosen just because of the net metering threshold. Nothing otherwise magic about that.

And at least this is conceived of as a pilot program within one utility that would be cost based, that you might be able to use competitive benchmark, and the quantity would be capped.

You might have the tariff differentiated by size and type of technology. You might have a different one for concentrating versus PV, as well as project scale. And, again, you would have a capacity limit established for within the sponsoring utility.

What are the pros or the reasons for doing this. It would certainly create investor security for those solar generators. You could use it to create incentives for systems larger than the net metering threshold. You could target it very specifically at the near-term concentrating solar development.

It definitely contributes to the diversity policy driver that Mike discussed earlier, or diversity A, I guess. And it could be

established quite quickly, either independently or along with another path.

On the con side, this, by itself, doesn't fully achieve the diversity goals, just the solar part of it. And because we don't expect solar to be 33 percent of California's load realistically it's unlikely, by itself, to meet the 2020 goal.

Because of its scale, again, just solar, it's unlikely to substantially stabilize or hedge prices. And, again, the cap on quantity could cause a speculative queuing issue or undermine investor certainty. And that just means you need to figure out the mechanisms to put in place to address that. It's not any kind of a fatal flaw, it just means you need to think through these -- anticipate and think through these issues.

COMMISSIONER BYRON: Mr. Grace, --

MR. GRACE: Yes.

COMMISSIONER BYRON: -- I'm sorry I missed the reason for the 1 megawatt threshold.

MR. GRACE: That was chosen just because of the net metering limit, below 1 megawatt, has net metering as a policy to drive it. So, just for discussion purposes we decided to focus this

as above 1 megawatt. Again, nothing that we're anchored to. There may be better ideas as far as whether a threshold is appropriate. And if so, what it is.

MR. TUTT: Mr. Grace, that's also the threshold for getting incentives from the CSI program, is that correct?

MR. GRACE: I believe so, although maybe I'm the only one in the room who hasn't --

MR. TUTT: I think you can install a large --

MR. GRACE: -- followed that one very closely.

MR. TUTT: -- a larger system than that, but you only get incentives for 1 megawatt -- up to 1 megawatt.

MS. SPEAKER: That is correct.

MR. GRACE: Okay. Policy path number five is biomass only. This would be open to sustainable biomass, however one might define sustainable. That's a whole other discussion.

Greater than 1.5 megawatts only, and cost based. So, this would be open within the full marketplace, at least all the IOUs in California. The price would be set on a cost

basis, and would be calculated to consider a sustainable yield of local biomass sources. So, you know, the concept of sustainability within biomass is a particularly important one for the policy to work long term.

Unlike all the other policies, this would have a shorter contract duration, exactly what it is we're not putting a stake in the ground yet. But think of it as short- to medium-term. And this is mostly because of the market structural inability for biomass plants to really have lock-in and have price certainty on their fuel, at least for many biomass sources, unless they really own their fuel sources.

That's been a challenge in biomass contracting. So here that might be a reason to have a shorter term which makes it more likely that the biomass plants could understand the cost structure and potentially contract to hedge it.

Tariff differentiation here might be by fuel type, by size. You might have different for biomass CHP versus a greenfield plant, different for gasification versus not, different for anaerobic digestion. So there are a lot of choices here that you may want to specifically

target.

What are the advantages of this. Well, it responds specifically to executive order S-0606, contributing to the diversity B goal in the policy drivers. And it reinforces the importance of sustainability in biomass feedstocks more explicitly than has been done within the RPS context.

And as well, it could be established quickly. And just like path number four, either independently or along with another path.

On the con side, it doesn't, by itself, achieve the diversity goals and, by itself, would be unlikely to meet the 2020 renewables targets.

The final path that we're putting forward for discussion is policy path six. We'll call this German style, for under 20 megawatts. So this has a lot in common with the first option, but it is focused on the gap that we really, I think, came out of workshop number one, the comments and dialogue at that workshop.

It seems like below 1.5 megawatts was well taken care of. And now with the passage of, over the last couple days, of both 380 that's now institutionalized. And many were arguing that the

over 20 megawatt, the larger projects, are well handled by the RPS.

So, if that's the case, it seems like maybe there is a gap, that there are small projects that could benefit from a feed-in tariff. So, again, here we would have open to all resource types, new resources as well as potentially a separate pricing for repowering, long-term contracts, cost-based.

And because we're talking about smaller contracts, smaller projects under 20 megawatts, we could probably go without a cap here and not worry about the overall volume as much as we might otherwise.

The pros are generally similar to option number one, and this does respond to that stakeholder concern about the gap between 1.5 and 20 megawatts that doesn't seem to have as effective policy supports. The smaller size limits the cost impact.

On the con side, the generator size limits are going to limit the ability to progress for this by itself towards the 2020 goals. But maybe in concert with the RPS, that works just fine.

And with all of the price cost-based options, it's always going to be a challenge to administratively choose the right price. But, again, that's been done and we have a lot of lessons learned and experience elsewhere in how to go about doing that and how not to.

So, those are the independent paths. Let me talk for just a moment about how they might interact. The time --

MR. LEAON: Bob, if I could interject. I apologize. We had a request from WebEx from someone that can only participate through noon, and they would really like to get a question posed to Wilson's earlier presentation.

So if we could just take a break right here and get that question in. Let me ask staff if we can get that person on the phone line, is that possible?

MR. FLESHMAN: Her name's Julie, can you call her out on the phone?

MR. LEAON: Yes. The question was from, I believe it's Julie Blunden from Sun Power.

MS. BLUNDEN: Yes.

MR. LEAON: Here we go.

MS. BLUNDEN: Thanks so much. First of

all, Bob, I apologize for interrupting you. You were doing a great job. And thank you very much to the Commissioners and Staff for allowing me to jump in. But I didn't realize I wasn't going to be able to do that on the phone, so thank you for taking the question.

I'm with Sun Power, and I have responsibilities for global public policy, which means that our about 1.4 billion in revenue in 2008, if you look historically at our percent in Europe, it's over 50 percent, so it's a substantial amount of business we do in Europe. And therefore we pay very close attention to what's happening to feed-in tariffs there.

As you know, Sun Power's part of the solar alliance which has been working with stakeholders to put in a 2 to 20 megawatt feed-in tariff concept to fill the gap that Bob was just talking about.

I just wanted to go back to the German and Spain discussion because there's so much going on there since June of this year that I think it's important to put a little nuance around some of the things that are happening there, and the themes of conversion on policy design and market

development that are really worth understanding why are Germany and Spain going the way that they are. And how are they getting more similar to markets around the world.

PV is absolutely the most controversial feed-in tariff element in Europe because of price and budget implications. Germany's price issue became a major part of the negotiations on the EEG changes in June somewhat to the surprise of the German Trade Association. Where a 30 percent reduction was proposed, but did not make it through.

However, a bunch of new elements of that feed-in tariff were put into place. The two most -- the three most relevant from this conversation are number one, changes to the digression rates that are dependent on the amount of market penetration by year, which is a step in the direction that California went with the CSI, recognizing penetration -- the amount of decline in feed-in tariff.

The second being offering an option for smaller rooftop customers to use net metering in combination with a feed-in tariff, which is actually the way that it works in Italy today.

And third, putting a registry in place. There has been no registry in Germany. There is one in Italy. There also has not been one in Spain. The consequence of that is that although you may know the price that you're paying for solar as part of the feed-in tariff, you haven't known what the budget impacts were going to be until several quarters after the end of the year.

That will change in 2009, which has the potential to change the political dynamics around the next round of EEG revisions which will be -- a report will be established next year and the revisions would be handled the year after that.

In Spain we also have a new registry. The feed-in tariff came out of the ministry last Friday evening. There are all kinds of interesting new datapoints there. The most interesting, I think, for us is that the Spaniards have very clearly said, we intended to put a rooftop program together.

In fact, the rooftop provision for 2009 is actually 267 megawatts compared to 133 for ground-mount. There's another 100 megawatts available for either. However the ground-mount megawatts are including any project that was

supposed to be in by the end of September that didn't make it.

So there's an assumption that a lot of those megawatts will be eaten up by ground-mount systems that were not fully commissioned by the end of September, September 28th, which is the last day that day that -- finance the old feed-in tariff.

Spain -- I said there was price and budget. Spain is all about budget. They were extraordinarily concerned about the fact that within 18 months they had 2 gigawatts roughly brought into the Spanish market as compared to the previous 12 months of about 250.

So the consequence of the rate of change of deployment of solar in Spain really created massive political backlash. And has created a completely new approach to the feed-in tariff going forward, with very clear caps that are going to be assigned quarterly and redeployed between system sizes on a four-times-a-year basis.

So, Spain has basically clamped down and said, we can't afford an uncapped feed-in tariff, which by the way, is indicative of the reason why you haven't seen most of the rest of the feed-in

tariff states that you saw Wilson put up on the screen. There's a lot of grey on that chart.

Other than France, there is no other uncapped feed-in tariff market in Europe. And the reason is the same one that Spain has concluded. They just can't handle an unknown amount of money going out the door for solar. And the success of solar in different places -- another great example of 500 megawatts in the queue. It just sets people up for being concerned about the potential for success to the point of not being able to fund it.

Let me just summarize a bunch of themes that are, you can see in Spain and Germany, but you're now actually seeing across Italy, France, Portugal and further east in Europe.

First of all, registry. The governments must know, from a diligence perspective, what's happening in their markets. And only Italy today has a real-time information source for knowing what's happening. In fact, the only two markets in the world that we have -- companies understand what's happening are California and Italy. That will change -- Germany -- the insertion of a cap on budget.

You know, pricing in Europe has been very robust. But the budget issue has been very different. You can't rate pricing but a low budget and have no feed-in tariff success.

So the question how to handle the cap comes up as a major issue, and one where we're trying to work with government to look at a penetration-based cap approach, which is we went one step towards in Germany, but I think there's probably continued improvement there. And we're talking about that.

The other element is a real theme is net metering coming in as both a bridge and a backstop. What I mean by that is as a bridge there's no basis for figuring out what happens at the end of a feed-in tariff market. Even if you reach retail electric rate parity and pricing for solar, what does that mean if you're selling it at wholesale. It doesn't mean anything unless you have a net metering provision in place which happens in Italy. We will now have it in option in Germany. And Spain has indicated an interest in looking at that.

And so you see the convergence of the notion of feed-in tariffs and net metering in

Europe.

The other thing that I think is super important to recognize is this notion of rooftops as the market that was intended for feed-in tariff design. We've an accidental brown-mount market in Europe, which is now the concept that in Spain people are building 10 megawatt, 20 megawatt projects including us, in 100 kilowatt increments. Which is incredibly counter productive because it raises the cost of the system relative to what it ought to be, because we're chopping it up in little bits in order to come up with a larger plant.

We've essentially seen Spain clamp down on that. We've seen Germany clamp down on that. I think what we're going to end up with is a feed-in tariff market that's designed first and foremost for rooftops. And allow some ground-mount assistance to go forward.

But the provision that we proposed in California for distributed power plants using a feed-in tariff would really be the first global feed-in tariff that was specifically designed for distributed power plants. And I think that's an important recognition.

Looking to Europe for the fact that they even end up with power plants in Europe, in fact, we did the first one in 2004, it's been an outcome of an unintentional consequence of market design.

At the largest end of the scale, utility scale, there is no utility scale PV market today in Europe. And the reason for that is because the goal of the government -- to put feed-in tariff in place to achieve rooftop market penetration, not utility scale. In fact, it's considered it's not a possibility to the utility scale for PV.

I think we have just surprised everybody with an announcement with PG&E that Sun Power did for 250 megawatts, an -- solar for 550 megawatts in August. And that indicates that there's an opportunity for us to reconsider how we do feed-in tariff or other policy design in Europe for utility scale.

Importantly, in Spain, there's a 50 megawatt cap utility scale wind and utility scale CFP. As anybody knows who's been watching the CFP plants go in in California, people aren't doing 50 megawatt scale CFP plants in the U.S. because that would be undersized for the optimum price.

The reason that they've done that in

Europe is because they don't want the project, very large projects going in willy-nilly on the transmission grid. And basically in order for us to move to a situation where we could do true utility scale CFP or peaker plants in Spain or other parts of Europe, we're going to have to go through a process that starts to move more towards the RPS in California, in that we need to be able to integrate from a transmission perspective, which brings up a whole new can of worms.

But it's not as simple as just going in and saying, if we put in feed-in tariffs for utility scale, as well, we know that we can't ask for that in Europe. And that we're going to have to ask for something that considers the transmission impacts of going in at 250, 550 scale megawatts.

The very last point I'll just make is that we do have two different mechanisms of recovery of cost for feed-in tariffs in Germany versus Spain.

In Germany it's ratepayer-funded. And Spain is taxpayer-funded. That's a very important distinction at this particular time in Spain, given the declining economic condition, which

reinforces the need for coming up with very clear caps that won't be exceeded.

But there's clearly an interest in moving to ratepayer funding, but that's something that will -- that's not an easy fix. It will take considerable amount of time to be able to move from one funding mechanism to another. And the political realities and constraints around funding for feed-in tariffs, I think, are influenced by whether they're taxpayer funded or ratepayer funded.

So, again, I thank everybody for your willingness to allow me to participate before noon. And I want to compliment both Wilson and Bob for doing a fantastic job of providing an overview of feed-in tariffs generally. And I thought I'd just add a little extra on solar feed-in tariffs because they tend to be the thing that people get exercised about when they talk about European feed-in tariffs.

MR. LEAON: All right, Julie, thank you for those comments. I don't think we have time to indulge in questions at this point. I'd like Bob to go ahead and continue with his presentation.

MR. GRACE: Thank you. Okay, we're

going to move here from talking about the policy paths to the potential interactions.

So, among the policy paths that we've laid out, we have some that have different timing, different scope, and different triggers. And those create some implementation options. So, while distinct, these are not all mutually exclusive and completely independent alternatives.

So that means we can think about their interactions and potential trajectories. Some could be adopted in concert with others. Those that are partial market or pilot scale or limited duration can be thought of as potentially working together along a policy trajectory.

On the other hand, some of them could be adopted while waiting for a specific trigger, like option number one, before taking more comprehensive action, can allow us to maybe take some initial steps. Maybe a go-slow approach, let's get our feet wet with something more limited before launching a more comprehensive feed-in tariff policy regime. And in the process buying time to prepare, it it's necessary, to implement that regime to ultimately meet the 33 percent goals.

So here is a schematic diagram focusing on one of these potential policy trajectories or combination of paths. Here we could have, at the top we have the RPS and the current feed-in tariffs that are already operating. And we could wait for the trigger question of the RPS meeting the 2010 target. If no, then you would implement option one. If yes, then you wouldn't.

One could, in parallel, start with either options four or five or both. Looking at the solar, more limited solar option or more limited biomass option. And then thinking how those play out several years from now. If option one was triggered then you could fold that into the bigger option one. And not have something separate hanging out there. And if not, then these could continue indefinitely.

And again, here you can see that you could also have the opportunity to determine whether the pilot program, the solar was conceived as a pilot, was successful. If not, you could terminate it. If yes, and an option one wasn't triggered, then you could continue that into the future. If yes, an option one was triggered, you could fold it into option one. So this is just a

way of thinking about how these things could play out over time, as well as a timeline on which they could play.

There are certain other possible interactions. You could draw a similar policy trajectory map from the perspectives of policy paths two, three and six. Policy path four can be thought of as a transition to a broader policy. And if so, it would be applicable to all the utilities. Again, that was conceived, it was a pilot that might just take place in one utility.

Policy path five, on the other hand, would either constitute its own path or could be an adjunct to a broader policy path or folded into one over time. So, again, an opportunity to think about how these might fit together.

All right, so we've laid all those out, we've heard about the context of what we can learn from Germany and Spain. Where do we go from here.

We've laid out six policy paths as representative alternatives. They will form the basis of discussion this afternoon, the panel, and opportunities for input. The Commission Staff is certainly looking to identify policy paths for which there is support, for which there's maybe

not strong support but a lack of material opposition. At least it helps understand which paths are available to consider further.

Those paths that can be implemented in the short term, ultimately those paths that can work, because to get there is going to require a degree of stakeholder buy-in, clearly.

And the Energy Commission is also looking to identify some specifics here. We've taken the step of putting out specific strawmen which, you know, they may cause reactions ranging from, that's a great idea to, god, no, not that one.

But, you know, we want to get some specific understanding of the basis of opposition or barriers of concerns. And that's what we're hoping to develop to move forward that maybe small changes, small tweaks in what we put forward that could mitigate those concerns. And so we want to be able to focus there.

Clearly, stakeholders have raised issues, concerns about the possibility of feed-in tariffs coexisting, expanded feed-in tariffs coexisting with the current RPS solicitation process.

Again, with specific proposals, specific concepts to deal with, we're hoping that we can elicit more specific concerns of what wouldn't work and why wouldn't it work, and is there anything that we can do about it that would make it work.

So, that's where I intended to wrap up. I'm happy to take any questions. But hopefully we've laid the groundwork for this afternoon.

MR. LEAON: We'll start with questions from the dais.

CHAIRPERSON PFANNENSTIEL: I see none up here, thank you.

MR. LEAON: Okay. Given our time situation, let's take a couple questions for Bob now. Do we have any questions in the room? If you could get those blue cards up. And, again, we will have time this afternoon to go into this in more detail. So I'd only like to take maybe five minutes here, and then let's hear from Molly Sterkel with the CPUC. And, again, Bob will be available this afternoon. We can get into these questions in detail.

Okay. First speaker request, Richard Raushenbach (sic). Green Volts. Sorry if I

didn't get your last name correct.

MR. RAUSHENBUSH: That was close enough. Richard Raushenbush with Green Volts. I was just curious about your option number six, which was focused on renewable generators less than 20 megawatts.

I was wondering whether you had calculated in or done an analysis of the potential benefits of that size in terms of avoiding additional transmission costs. As I noticed that that was in the recent RETI report that there were available locations near distribution substations.

MR. GRACE: No. We certainly haven't had the opportunity to do a lot of analysis of the specific cost or quantity implications here. At this point we're, you know, a step earlier in just trying to craft the policy options. I think certainly a next step for those that seem to have legs would be to start getting into more quantitative metrics and understanding those impacts.

MR. RAUSHENBUSH: Thank you.

MR. LEAON: Next speaker, Carl Zichella, Director, Western Renewable Programs, Sierra Club.

MR. ZICHELLA: Good morning.

Unfortunately, I'm going to have to take off; I won't be able to be with you over lunch. So I had some quick comments on the presentations this morning and on the overall discussion about feed-in tariffs.

I want to first thank you all for doing this. This is really important. And having this kind of conversation about something that has had a good track record in Europe is really important, that we not overlook things that are actually working.

Obviously our present system isn't getting us the kinds of renewable development that we need at the pace that we need it. Some of our tools are work. Some of them aren't working as we expected to. So, hopefully we'll be able to utilize new techniques like feed-in tariffs to help us accomplish some of these goals.

The Sierra Club is interested in feed-in tariffs because the ability to incentivize a rapid gear-up, which is exactly what we need. We have to start making much more progress, especially in the rooftop sector, if we're going to be able to get much of the benefits out of that sector to help us influence some of the other work that

we're doing.

Cost and profit pricing, cost-plus profit pricing is something that our folks believe is the approach that we need to be taking. I realize there's a lot of variability in that as this morning's presentations indicated.

That's actually one of the strengths of this is that that it can be tailored to suit our needs. We aren't stuck with just what's been done in Germany or Spain. And we have the ability to take advantage of their experience in crafting something that's peculiar to California that specifically meets our needs.

One point we wanted to make, and we will have written comments, by the way, that we'll submit later for the record. But there's a cost aspect to this that's been overlooked, and that's the economic stimulation effects of this rapid buildup.

It has had a huge benefit in Europe. It's created many thousands of jobs. It has the opportunity for us here in California to address employment needs in some of our most distressed parts of the state.

So I think, you know, we need to begin

to somehow take into account the ancillary benefits of a rapid gear-up of renewable energy development, especially in the solar side and on the rooftop aspect of it.

If we were able to gear up and we are going painfully slow now in the rooftop sector in California, we might be able to get some additional benefits that help us reduce our buildout costs and transmission costs and needs.

That's been raised in previous workshops. I think until we have incentives that actually permit rapid development of these resources, we'll probably never get that benefit.

Obviously it's an easy to administer program which keeps the costs fairly low. That's another benefit of a feed-in tariff approach depending on how you structure it, of course. And given the many combinations of elements, you could actually complicate the system. But it appears that it's one of the main benefits and was cheaper than REC markets in Europe. And that may be a substantial reason why.

I think I'll stop there and just reserve the rest of the comments for written comments. Give others a chance, also. I just want to say I

really really appreciate the opportunity to have this conversation.

COMMISSIONER BYRON: Mr. Zichella, I appreciate your comments. Since you track this so closely, do you have any sense of what may be an impediment or impediments here in California in implementation of feed-in tariffs?

MR. ZICHELLA: To the feed-in tariffs. I think that there's a considerable amount of investment that's been made in the tools that we've already developed. And looking at reducing or combining other new tools with those, like the RPS, for example, might run into quite a bit of resistance from people that really believe that's just getting geared up, just getting started.

There's no question it's driving procurement. We're not seeing a lot of success on those contracts. We have to clear away one of the main impediments, which is getting transmission developed.

It's interesting to me to see the various ways of sort of spreading the costs of feed-in tariffs out. One is to go straight through the ratepayers. The other is to go through the taxpayers.

One makes it -- the taxpayer approach, obviously that's more taxpayers than there are potentially ratepayers. So you have a chance to keep the costs lower per person. But there's an equity issue there, too, about who's actually getting the benefit of those things.

I just think that we need to be able to think bigger and outside of the boxes that we're in. I think the California Solar Initiative, the incentives in that initiative have not been as effective as we would wish.

And I think the people that thought that through and helped develop that may be among those who are not very positive about feed-in tariff development in California.

We have to do this together. We have to help fit these pieces together. Some of the things that we've got are working, they're just not working as well as we would wish. There's no question that we have to do a better job and gear up faster if we're going to hit our greenhouse gas reduction goals.

COMMISSIONER BYRON: And I know you're working on the transmission issue, as well, so thank you. Thank you for your remarks.

MR. LEAON: Okay. Next speaker, Pete Gregson, Advanced Solar, Hydro and Wind Power.

MR. GREGSON: Again, thank you very much; thank you, Commissioners. I'm kind of surprised there's no discussion on Japan and Korea.

Korea has had some major large installations, especially ground installations because of feed-in tariffs. And the ground installation has actually stimulated growth in the solar industry with a different technology, not just monopoly but also thin film. So the potential of ground systems creates a better spectrum for the industry.

The other thing I'd like to address is when you talk about transmission upgrades, the way it works right now is if you're an independent installer you're going to pay for the transmission upgrades. If you're lucky enough to be a utility company then it falls onto the ratepayers or it falls onto the taxpayers.

So, getting to the two examples that my esteemed colleague from Sun Power brought up, part of the contingency plans for those contracts is that they pay for the upgrade of the transmission

system.

So how it works is that we, as installers, pay for the upgrade of a transmission system. If a utility company puts in the system, we as ratepayers or the taxpayer, pays for it. That's another way to look at this.

Another thing I'd like to alert the Commission to is when you look at the solar industry it's a global industry. We are competing with manufacturers basically coming out of China right now. Major manufacturer coming out of India.

Most of the manufacturing coming out of the United States doesn't even want to sell in the United States, because we are not competitive enough. Because of the feed-in tariffs in Europe, Spain, Korea, Japan, the price of solar, because of the investment potentials, is much higher. They get much higher price per watt than we do in the United States.

So, what happens, we in the United States have to compete with the European market, but we don't have the incentive to keep up with that competition.

Basically look at something like BP,

Evergreen, they'll come right out and tell you they don't want to even sell in the United States. You look at all the manufacturers in China, they will literally tell you they don't want to sell in the United States.

We cannot keep up with the investment potential of Europe. And, as I keep saying, Japan and Korea.

The other thing you look at is especially in Germany the RECs, the REC value in Germany is $32 a megawatt. Where in California the biggest buyer of RECs is PG&E at $8 a megawatt.

The incentive right now in Japan, because of the economic issues, and I think we're approaching that rapidly in the United States, is they are gearing up their rebate and input tariffs basically to promote their manufacturing plants in Japan. Because they have got hit so hard because of the European market.

Thanks.

MR. LEAON: Thank you. We have one more speaker card, and this will be our last question before the next presentation. Tom Faust with Redwood Renewables.

MR. FAUST: Good morning and thank you very much for the really good presentation. I really enjoyed Wilson's presentation.

One thing that he seemed to -- he didn't point out was about 40 percent of the feed-in tariff in Germany is created on rooftops rather than from solar farms. And that's a huge market that we're missing here in California, in the United States, is the locally distributed energy that can be created on people's rooftops, that can be then transmitted to the new plug-in PHEVs that are going to be in abundance. It's a natural, just like bread and butter, cheese and wine. It's a natural combination.

And options two, three, four, five and six are all limiting. The feed-in tariff option one that was presented, that is proven that that seems to be the best choice for California to really energize its feed-in tariff markets and really grow the renewable energy market. And accomplish all the goals of the Air Resources Board.

Thank you very much.

COMMISSIONER BYRON: That's an excellent comment. I'm really glad that you brought it up.

I forgot to ask that question in the first presentation. And is that true, 40 percent in Germany are on rooftops?

MR. FAUST: Yes. Yes, it's 40 percent. And the California Solar Initiative, as everyone knows, is not accomplishing any of that. They thought it would be split 50/50, commercial and it's not doing that.

But if you had a feed-in tariff you'd have everyone would be incentivized to fill up their car with energy off their roof. You would see greenhouse gases just really dropping off. It's a great market idea.

Look at Anton Minor from Solar Cities invested in both those. He sees the logic by linking them together. And I urge the Commission to really consider what's logical, what's natural and what's proven.

And the German option one that's been presented here will grow the market. It'll not encourage -- all the other are encouraging status quo and they discriminate against small producers. And that's what we don't want to do. That's what the Germans haven't done. And that's why it's so popular with the whole country.

And that's what you got to do, is you know, you just can't have all benefits going to one group. You have to diversify and have everyone participate in the program. And by having the rooftop, this, then you diversify your support for your programs.

Thank you.

COMMISSIONER BYRON: Thank you. Thank you for your comment. And this is really what I meant earlier in my comments, although I didn't state them as well. This is perhaps really -- great opportunity when we think of things only in the context of the investor-owned utilities. Clearly the opportunities in private see private capital entering into the generation market. And we're not rate-basing these on the backs of customers. There's a certain advantage there at least to be thought about. Again, outside the context of the investor-owned utilities.

So that's a good comment, thank you.

CHAIRPERSON PFANNENSTIEL: Mike. We were going to suggest, with Molly's indulgence, that we take a lunch break now, and then come back. Is that --

MR. LEAON: That is an excellent

proposal.

CHAIRPERSON PFANNENSTIEL: -- acceptable to Molly?

MR. LEAON: I checked with Molly. She is fine with that, and she promises to keep everybody awake after lunch.

(Laughter.)

CHAIRPERSON PFANNENSTIEL: Why don't we do the hour and a half then that we had originally planned. Come back at 1:30. An hour and 15 minutes. Right.

MR. LEAON: 1:30, okay.

CHAIRPERSON PFANNENSTIEL: 1:30.

MR. LEAON: We will reconvene at 1:30.

(Whereupon, at 12:16 p.m., the workshop was adjourned, to reconvene at 1:30 p.m., this same day.)

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AFTERNOON SESSION

1:44 p.m.

MS. STERKEL: I don't have access to current 2008 data from munis. I expect when the CEC compiles the statewide data sometime early next year that we'll all see it at the same time.

But I know that for the IOU territories we're over 100 megawatts in 2008.

So, now moving from the types of programs that subtract from the demands forecasts for the state, and moving on to the supply programs, we have currently three major programs. And, again, this is probably not comprehensive. I thought of a fourth which I'll mention -- when I was preparing my remarks.

But the first major set of programs that in the area of distributed generation that are qualifying facilities. As most of you probably recall, the CPUC approved a series of standard offer contracts in the 1980s. What is referred to as avoided cost. That's based on the PURPA Act from 1978.

And under the Act we installed -- we provided independent generators -- well, we proved

that independent generators could come online and be part of the electricity supply here in California. And the contract prices varied by size and whether or not you had as-available capacity or firm capacity. The prices were mostly tied to the price of natural gas.

As a result, you know, like I mentioned, there were about 8600 megawatts of capacity that came online. And the CPUC suspended that program due to over-subscription in 1985.

Not all of that capacity was -- is renewable. But that is where a significant portion of today's renewables comes from, it's from the QF capacity that came online in the early 1980s.

That's very similar to the topic of today's workshop which is a feed-in tariff. A feed-in tariff has attached to it a standard offer contract, or standard offer contract for a power purchase agreement.

So when the QF program --

MR. KINOSIAN: If I could interject for a second. I'm very familiar with the QFs. I just wanted to mention that for the standard offer contracts, renewable resources actually can get

fixed price contracts for ten years. They weren't tied to gas prices. Combined heat and power projects had prices tied to gas prices. There was a differentiation made depending on technology.

MS. STERKEL: Right, there was a differentiation. And a variety of different types of contracts, you're absolutely correct.

And so when the QF programs, the renewable energy industry here in California definitely experienced a shock. And there was a hiatus of a significant period of time before when contracts were not available.

So, with that experience, at the staff level we've been watching what's happening in Spain and Germany because currently -- the current news out of Spain is that they just extended their feed-in tariff. But, of course, it does echo the problems that we experienced in the 1980s of when there was an over-subscription that there was a suspension of the program. And then that caused the market to have serious disruption. And so, we, you know, have been cautiously watching that.

It is worth noting that the CPUC in 2007 re-authorized a new standard offer QF contract in the 07-09-040, a new revised avoided cost formula.

Most people think it's a decision as setting the price for the old existing QFs. But it also did open up the possibility that new folks would be able to get new contracts under the QF program.

And so it on this slide because it's a form of potential procurement, and it also -- it is a standard offer. The contracts are still in final negotiations. They've been in litigation for quite some time.

CHAIRPERSON PFANNENSTIEL: I have a specific question. The standard offer contracts were, in fact, contracts. And as I remember, that was the problem when they ended up being way over market. But they really were enforceable contract and could not be abrogated.

Whereas I didn't understand that the feed-in tariffs in Europe were, in fact, -- I know that they are set for a long period of time, but I have no idea whether those are actually contractual obligations the same way our standard offers were.

MS. STERKEL: You know, I --

CHAIRPERSON PFANNENSTIEL: Do you know that?

MS. STERKEL: -- don't know that, but I

can tell you that the feed-in tariffs that we have in place today in California are tariffs that are available at terms and price conditions as set in the attachment A, which is the standard offer power purchase agreement.

CHAIRPERSON PFANNENSTIEL: So which is very different than being contractual.

MS. STERKEL: Correct.

CHAIRPERSON PFANNENSTIEL: Because if they are contracts, they can't get changed necessarily, without the agreement of the two parties.

MS. STERKEL: Right, the --

CHAIRPERSON PFANNENSTIEL: The tariffs can be changed by the PUC.

MS. STERKEL: Tariffs can be changed by the PUC, but I believe once the PPA goes into effect, that that is a contract between the PPA, the two signers of the PPA.

CHAIRPERSON PFANNENSTIEL: Okay. My question really then is to whether -- what that obligation is in Europe. How that works.

MS. STERKEL: I think that that's a good thing to investigate.

So the second form of contract is, of

course, the RPS program. I'm not here to talk about the RPS program, but, of course, it has competitive solicitations as well as bilateral contract.

One thing to note about the bilateral contract is that it includes a standard offer contract for the sale of energy from a qualifying DG facility to the grid. And there is an example in place today which Edison -- standard offer contract. That's part of their RPS suite of RPS plan. And part of their RPS plan is to offer that standard offer.

The third, and then the third type of utility procurement program is the small renewable energy generation tariff. And the main one I'm here to talk about today is the one that was sort of kick-started by AB-1969, the Yee Bill. And we refer to that as a small renewable generation tariff. And the second one is the AB-1613, which is the CHP feed-in tariff, which is not yet implemented by the CPUC, but is currently under consideration at the CPUC. So it kind of fits in here. And, of course, CHP could be renewably fueled, and so that's why it fits in the topic today.

A fourth bullet, if I had time to re-do the slide, I would add utility-owned programs. Before the CPUC right now we have two applications, one from Edison and one from San Diego Gas and Electric. Both applications seek approval to purchase distributed solar PV and add that their procurement portfolio.

So, I think we can just move on to the next slide. The characteristics of all of the programs that we've just been talking about are that these energy and capacity is used to meet the utility procurement obligations. Energy generally can be scheduled. Resource adequacy generally counted as supply.

And the projects are, you know, may be located at end use customer sites, but are generally intended to be sized greater than onsite load requirements. So they're designed to be net exporters to the grid.

And so CPUC rule 21 or FERC interconnection rules applies to the interconnections. They're not exempt from interconnection charges. Generator is generally located on whatever the terms of the contract are. And the cost to the utility, you know, shows up in

the generation portion of electricity rates.

The programs that we referred to previously, the customer-generation programs where we have incentives, those costs are often show up, or most of the incentive program costs show up in the distribution rates, not in the generation portion of rates.

And the other characteristic of these programs is that they're generally bought by the utility, not by energy service providers or by munis, although they certainly, you know, I think other electricity providers could buy these types of products. But that is, of course, you know, has implications for the discussion on feed-in tariffs. Where earlier we were talking about Germany and Spain where they had a nationwide policy. And then, of course, these utility programs are neither statewide nor nationwide. So there's a different cost spread, cost recovery mechanisms.

So, I think we can move on from there. So let's just talk to the specific case about the small renewable generation tariffs, sometimes called the AB-1969 tariff.

The CPUC approved these tariffs in

February of 2008. The decision that authorized them actually is from July 2007, but they went into effect on Valentine's Day this year. A nice easy date to remember.

They were originally authorized for generators under 1.5 megawatts owned by public water and wastewater facilities. And one of the reasons was that these tariffs facilitate a streamlined interconnection process.

The tariffs have been expanded to all customers of the three IOUs, so that includes PG&E, Edison and quite recently the Commission acted to include SDG&E in these rates. And SDG&E actually, their tariff has just been filed with us. It's not yet been approved by the energy division or the Commission, but that is on file with us, and we expect it to be available to customers in that territory very soon.

The statewide cumulative capacity is just about 500 megawatts. It's allocated proportionately by share of total peak demand per the statute. And there are two different contracts under our feed-in tariffs, depending on the customer's choice, the full sale of the production or excess sales after onsite usage.

Customers are eligible for 10-, 15- or 20-year contracts under the terms of the tariff.

And if you'll go to the next slide we'll talk a little bit more about the pricing terms.

COMMISSIONER BYRON: Before you do, can I just ask a couple of quick questions on this slide. You may not be able to answer these, but I've always been curious, is it still limited to public water and wastewater facilities?

MS. STERKEL: There are 200 -- of the cumulative capacity, 250 megawatts of that is limited to water and wastewater facilities. And about 248 is available to nonwater and wastewater utilities. And so that's what I was trying to get to when I said all customers in that bullet.

COMMISSIONER BYRON: So, --

MS. STERKEL: So a water and wastewater facility would be one type of customer, as opposed to any customer.

COMMISSIONER BYRON: So, this -- Robert may be able to answer, but what I'm interested in is trying to understand how this came about.

MS. STERKEL: How did it come about?

COMMISSIONER BYRON: Yeah. Why is it just wastewater facilities? Why is there such a

number like 498? I mean --

MS. STERKEL: I think the --

COMMISSIONER BYRON: -- I know there's --

(Parties speaking simultaneously.)

MS. STERKEL: -- I can answer both of those questions.

COMMISSIONER BYRON: Okay.

MS. STERKEL: The first 250 megawatts was actually, it was because of AB-1969 was written by Assemblymember Yee in 2006, and asked for a feed-in tariff to be made available to water and wastewater customers, period.

The CPUC -- I'm sorry, I can't remember if the 250 megawatts came from the actual authorizing legislation -- I'm getting a nod, yes. And so then when the CPUC implemented that legislation it asked in its implementation whether or not we couldn't make the exact same contract available to nonwater and wastewater facilities. And the answer in that proceeding was yes.

And so then they said, well, how much. And so we said, well, how about another 250 for anyone else.

And the reason why this became 498 is

because the tariffs that apply to water and wastewater facilities also apply to not just the three major IOUs, but to the four minor IOUs -- forgive that term --

COMMISSIONER BYRON: So we had to proportion out those --

MS. STERKEL: Thank you, that's exactly. However, the extension to all customers was not extended to Bear Valley and Mountain Utilities, et cetera. So therefore that's where you get that missing 2 megawatts.

COMMISSIONER BYRON: So there is logic to it.

(Laughter.)

MR. KINOSIAN: Or something close to logic. I just want to add one other thing onto these programs, which is one of the things the Commission did in expanding this was indicated the projects that are getting subsidies under other Commission programs, such as the CSI, cannot also do the feed-in tariffs. So we do separate our self-gen programs and CSI from the feed-in tariff.

COMMISSIONER BYRON: No double-dipping.

MR. KINOSIAN: Right.

MS. STERKEL: Right. And Robert would

have probably helped me with my slides, and then added on the previous slide we were talking about characteristics are not characterized by incentives. So, I mean there's a price paid under these whatever utility procurement projects there are. But this is -- we don't necessarily -- we don't pay incentives because they're not characterized by that.

So, okay, the next slide. The rate available under these tariffs is determined by the market price referent, and adjusted by time of delivery for both season and time of day. And the market price referent was specifically called for in the AB-1969 statute.

So my understanding is that they wanted to have a feed-in tariff, they knew they needed to have a price, they wanted it to be maybe not litigated or an extensive period of time. And so therefore, the MPR was seen as an opportunity there.

The -- referent point of the MPR is that by a different law as the new combined cycle gas power plant, and so AB-1969, the MPR, the annual number, we get the annual number that is developed in the MPR for use in the RPS proceeding. And we

adjust it for season and time of delivery. And, voila, you end up with an actual payment stream. The market price referent is not actually a per-kilowatt-hour, per-day payment stream. But you do get one when you've made this adjustment.

And so in each of the utility tariffs in their tariffs you can actually see the price that's offered. And so, if you look in the table here you'll see that for this current year, what's available. The MPR is 9 cents. And then when you adjust that for time of delivery and season, you get a different real price depending on what technology you are.

And these contracts are available for all renewable energy technologies, including hydro, biomass and solar. And solar so often talked about in -- so often interested I included it here on the slide. The estimate that a solar producer would get, it was sort of because of their time of delivery factors. It kind of gives them a little bump-up to 11 or 13 cents, depending on which utility territory they're in, because, of course, they have different TOD factors.

COMMISSIONER BYRON: Well, and this is a crucial issue, so I hope you don't mind, but how

do we get this differential, because it's only 2 cents. And I would expect time-of-use mid-day peak to be a bigger differential. So who figures this one out?

MS. STERKEL: Right. The reason why is because there is, of course, a big bump-up for solar will get paid, I think, certain times of the year and certain times of the day will get almost 26 cents -- just as generation here.

And so I believe I was looking at PG&E's and it was, I think, 26 cents was at one point. That's how much you can get paid if you're solar for that summer peak period.

However, you're not getting that for winter peak prices. And so on average, balanced across the year, you get 11 cents.

COMMISSIONER BYRON: If I could, just a little bit further. My recollection, looking back at the old rate books, you know, it's mid-May to mid-October is when you're seeing summer peak pricing for regular, you know, 1920 customers, because that's what I'm familiar with. And so that's for six months of the year that customers are paying that higher peak pricing differential.

MS. STERKEL: Right, and the --

COMMISSIONER BYRON: And you're telling me that when you average it out over winter it doesn't just cut it by 2, if you follow my math, it really cuts it a lot more.

MS. STERKEL: Right. And there are probably people in the audience who can explain it a lot better than I can, but I do believe one of the reasons is that the time of delivery prices, which are those peak periods, they're only available for a limited number of hours per day.

So, let's say, maybe, a noon to 6:00 period. And solar is, of course, producing on the shoulders, and even a little bit on the offpeak potentially. So when you add in the fact that there's shoulder production and offpeak production throughout these other times of year, you come back down to it.

And this is just an estimate that staff provided. It certainly isn't -- what we did was we just simply took the standard solar production profile that's available publicly, and then we applied it to the time of delivery factors.

And if one particular developer thought that their technology had a higher capacity factor, they certainly could do their own

financial estimates and might come out with something a little bit higher than this.

But I did just want to pause on this slide and go ahead, and for everyone's benefit, just mention that when you try to compare these and say well, why aren't people signing up for AB-1969 tariff, although we have had a few people sign up, I don't think we've had any solar sign up yet.

And one thing, of course, is that the program has only been open really since February. But we do understand that these rates end up being a little bit low. It's kind of, if you step back for a second and think logically, it's because solar is, you know, so more expensive than a natural gas, combined cycle power plant. So that shouldn't come as a shock that we don't have a lot of people signing up.

However, I just want to give you a little bit of context for these prices. We look at average retail rates, the one that I always cite, I'm sorry, I'm a PG&E customer, so it's PG&E's average retail rates are about 14 cents. That includes transmission and distribution.

A solar project with an ITC and with a

CSI credit, we generally estimate that cost to be around 22 cents. Everyone has access to their own individual financing, and so it will vary based on their individual financing, but on the order of 22 cents.

Without CSI, and again these utility procurement programs, what the feed-in tariff is, you would not have access to the CSI. That would bump you up a couple more cents.

So in order to kind of -- so you might be talking in the neighborhood of 25 cents might be what solar costs, again depending on your financing.

So if we're offering 11 cents, and somebody probably can't make that quote-unquote paper out, and so we get something closer to 25 cents, you can see we would have to be, you know, offering a significantly higher price in order to tempt a lot of solar folks into the market.

I think what we've heard from people is, you know, we need to be on the other end of the teens, you know, we'd have to be much closer to 20 cents in order to get much interest.

In contrast, the German feed-in tariff is currently offering 57 Euro cents per kilowatt

hour, which works out to be about on the 80 U.S. cents. Even if you discount the fact that their solar production is half what ours is. And so, you know, maybe we could offer something like, you know, half as much, maybe 40 U.S. That still would be much higher than what we're offering here.

So, the difference, I hope you followed my math on that one --

COMMISSIONER BYRON: I do follow it.

MS. STERKEL: Okay. And I can't do the math, the Spanish one we heard was 34 cents times 1.4, I'm not going to do that math right now, but anyway --

COMMISSIONER BYRON: So I suspect you're a little bit more suspect of that .1 percent cost differential that we were talking about earlier on the German presentation?

MS. STERKEL: You know, I think that I heard differing estimates. I don't know what it is relative to the total size of the German electricity market. I think that's probably what's driving that answer is you have to know the total size of the Germany electricity market. And I just don't know that.

One thing that I do know that in California we have some experience when we pay wholesale generators, of which that's what these are, wholesale generators more than retail rates. We've had a very painful lesson here in California and don't need to go over history, but of course, the energy crisis occurred when we did have a sustained period of paying higher wholesale rates than retail rates.

And so I don't want to sound alarmist, but that could be a potential problematic situation. It doesn't mean that we can never pay a higher price; it just means that that's something that we need to weigh very carefully as to when and how much and how much can we do that. And for what, all the right political reasons.

COMMISSIONER BYRON: Fair enough. Let me make a couple quick points, if I may. And I did follow everything you said, that was very good, covered a lot of ground in a short period of time.

But, you know, there are other issues that come into play here. There's state policy issues, implementation of renewables that we want to accomplish. And there is a cost differential

associated with that. As long as we make that conscious decision, inform customers, that's a decision we should be willing to make.

The other is, and I don't think I said this very well, and I'll make it clear. I'm not necessarily interested in comparing MPR to the solar estimate.

I'm interested in comparing what customers are paying for peak summer rates versus what utilities are paying to meet that demand. That's the comparison that I think we ought to be making here for these highly valued mid-summer, mid-day electrons.

And that's the comparison, not against the MPR, but if a customer is paying 30 cents for peak power, then the utility ought to be willing to pay pretty close to that number to fulfill that need. And solar fits it very well.

MS. STERKEL: Right. And, in fact, you hit the nail on the head. Sometimes I get off the question of why does anyone go solar. It's, you know, at 22 cents it's more expensive than average retail rates at 14 cents. And it's exactly because of the math you just said. Because in PG&E's territory, tiers 4 and 5 are upwards of 30

cents per kilowatt hour. So for those customers solar already pencils out, solar already makes a lot of sense in California for certain sets of customers.

COMMISSIONER BYRON: We are on the same wave length --

CHAIRPERSON PFANNENSTIEL: And once we get rates that track across, once we have time varying rates at critical peak price rate -- with these meters that are going in, then customers will, in fact, see that price. And so it won't necessarily be the top tier. It will, in fact, be a price that is -- on a peak, presumably the PUC will adopt rates that do that. And it seems to me that can make a big difference.

MS. STERKEL: Right. I think that time-of-use rates will support solar industry -- those efforts.

MR. KINOSIAN: I was just going to say, you know one of those we're having at the PUC is the AB-1X restrictions --

COMMISSIONER BYRON: Right, --

MR. KINOSIAN: -- tiers, two rates. We are looking at whether or not there may be a potential to switch customers to TOU rates within

the confines of AB-1X -- residential TOU rates in effect factor in the energy crisis that could be compliance with AB-1X. That's something we're looking at.

CHAIRPERSON PFANNENSTIEL: But this also, the likelihood of being able to do voluntary time-of-use or critical peak pricing rate --

MR. KINOSIAN: We have those available to customers now --

CHAIRPERSON PFANNENSTIEL: -- customers that have the advanced meters.

MR. KINOSIAN: Right, and --

CHAIRPERSON PFANNENSTIEL: That maybe --

MR. KINOSIAN: Yeah, and we have those rates available as an option. You can get a new meter if you sign up for the rate now.

MS. STERKEL: I think we can move on to the next slide. I did want to mention that the CPUC's work on feed-in tariffs is not, by any means, complete. Currently under consideration in our RPS rulemaking, we're considering the expansion of the feed-in tariff. It's currently capped at, for facilities, up to 1.5 megawatts. And we're considering expanding the size to between 1.5 and 20 megawatts or someplace in

between. That's under active, you know, consideration at the PUC.

Comments have been filed in that proceeding. The CEC Staff is a collaborative staff in that proceeding.

Another item under consideration is how we count the excess sales towards the program limits, this 498 number that we were talking about. So that's sort of a smaller issue.

And also under consideration is whether or not the feed-in tariff can be expanded to allow third-party ownership of facilities. And that is, of course, a major financial construct that is, I think, popular under the CSI program, is that there are a lot of third-party owners of solar systems putting in CSI-funded systems for customer generators.

And so the question in this part of the proceeding is whether or not that same structure can be utilized under the feed-in tariff program.

COMMISSIONER BYRON: And why would it matter who owns the --

MS. STERKEL: I think that under the original tariffs of their originally proposed -- well, first of all, remember we were starting with

the water and wastewater facilities. So we wanted the eligible customer to be, you know, as defined.

And then I think under the tariffs that were originally proposed in the proceeding, it was just, you know, to make the tariff available only directly to that customer.

And so this would introduce a third party into that contractual arrangement. And so I believe the utilities wanted to comment on that before they just allowed it to happen. So that's why we were taking comment there.

COMMISSIONER BYRON: Of course. Thank you.

MS. STERKEL: Go ahead to the next slide. Okay, so also AB-1613, which was passed in 2007, the Blakeslee Bill, introduced the combined heat and power feed-in tariff for new combined heat and power facilities.

It's under consideration in a rulemaking that was in June at the CPUC. This contrasts, this piece of legislation contrasts with 1969 in that in the actual legislation it said that there could be fixed or variable price, as determined by the CPUC. So, sort of, one might say full ratemaking authority was granted in the

legislation to the CPUC.

The facility eligibility of CHP up to 20 megawatts, so just from the get-go it was intended for larger systems. And the CHP systems have to be sized to meet the customers' thermal load, but not necessarily to the electrical load.

It is intended for new CHP systems. And in the opening of that rulemaking we did ask for comments about the definition of new, whether or not that included repowered facilities. We do understand that there is a large -- of existing CHP facilities which are eligible for repowering and usually the CEC does some good work on the potentials of that.

And so that's one of the things that we'll be considering, is can we make that available to repowered, and exactly how do you define repower, et cetera, et cetera.

So, we look forward to working on that over the coming year. And it will be, I think the big question in that proceeding is how do you determine the price.

Do you want to move on to the last slide. One other thing going on currently, I did mention earlier that Edison currently has standard

offer contracts for biomass projects up to 20 megawatts available. And that's under RPS contracting authority.

The price they're offering there is set at the MPR. So it's similar to the 1969 contracts. And they offer three different types of contracts depending on the size. And the distinction there is that the contracts for the larger projects have performance and development security requirements.

And Edison proposes in its 2009 RPS procurement plan to expand those standard offer contracts to all renewable technologies. So, in essence, they propose doing something in their 2009 RPS plan, which is also under consideration in sort of the 1969 portion of the proceeding. So I think we're looking at sort of how much of an overlap hat really is.

I would also be remiss if I did not tell you that PG&E also, in its 2009 plans, has proposed a sort of a similar effort as a pilot program. And I believe there's some PG&E folks here, so they can probably speak more to that proposal.

But this is sort of just my conclusion.

I just want to mention that, you know, there are numerous, you know, contract paths for wholesale distributed generation in California. We'll probably see a lot of activity in this area in the next few years.

I think the big issue is always, of course, what is the price going to be. And that's where we need to do a lot of work, and look very hard at what prices can be offered and in what timeframes.

So, with that I'm happy to take your questions. I thank you very much for listening.

COMMISSIONER BYRON: Absolutely. Thank you for coming. I've said this before, my colleagues at the PUC -- my fellow Commissioners at the PUC, thank god there's one Commission that looks at the financial impacts, the cost to the customers.

And that you've got a good grasp of all these numbers that we're talking about. I know we're talking in somewhat generalities, but I -- and I should also add this is very valuable, a good exchange of information. Thank you for coming.

On your last slide you indicated some of

these programs are set at the MPR, the market price referent. What's your opinion about that? Is that the right place to set the price for renewables?

I mean biomass is a nice -- SCE currently has a standard offer contract for biomass projects at 20 megawatts. MRP, you know, might be the right kind of number there, maybe it's not. It's a dispatchable asset; it's highly desirable. Is that the right number for all renewables?

MS. STERKEL: Right. I mean I think that's a, it's a very challenging question. Whether or not we should have a technology differentiated, you know, price offering.

And I will say that I think there's interest in doing that. I think one of the concerns around that is the amount of litigation that it might require, and length of time --

COMMISSIONER BYRON: But that's another thing you all have to consider --

MS. STERKEL: Yes, yes, it's something we're also, unfortunately, good at, litigation. And not the real issue, because I think one of the things that's really driving interest, and

certainly Commissioner Pfannenstiel mentioned it at the beginning of the day, is, you know, we're interested in bringing more renewables online.

And we do know that we have a lot of contracts right for renewables, including renewables at the 1 to 20 megawatt level. I didn't mention, but there are about 50 contracts in the RPS program that have, as a minimum, five under 20 megawatts. So they might have an expansion potential.

But there are at least -- there are 50 projects, actually I think it's 49, that are publicly available on our website that say that our, you know, under 20 megawatts size initially. So there is a contract path for them currently through the RPS program. These are contracts that have gone through the competitive solicitation process.

So what we're talking about here is whether or not there should be a standard price offering either maybe differentiated by technology and time of delivery, but mainly, you know, whether there should be standard offer.

I think the concern there is if you set the price too high, you're overpaying. And if you

set the price too low, you're not getting anything. So, sort of it's a lot of work to do it, and so you're going to balance the pros and cons.

Just in terms of one more figure for you to keep in mind. The California Solar Initiative, which was by no means had a small price tag associated with it, was authorized by the Legislature in 2006. It's a $3 billion, ten-year stream of incentives.

And that $3 billion number is a very significant -- has a significant impact on ratepayers. Designed to grow the industry at a sustainable pace, and get us to 3000 megawatts. We're growing at about 40 percent a year, and we're hoping that, you know, as the incentives slowly decline that gives the industry time to ramp up and lower the cost to the customer.

In contrast, some of the European markets have grown at much higher rates. And, you know, at the 400, 500, 600 percent per year in, you know, not every year, but they've had these big jumps. And that's very difficult for the industry to sustain.

And it's also quite expensive. I mean

the German -- I think the big missing piece of information is not only is the total cost, the impact on ratepayers, but also even just the total cost of the German program.

I do know from the German Solar Energy Industries Association, they told me that the price tag in 2006 for all the installed solar in 2006 was $1 billion Euros for that one year. And that's a price tag that they have to pay every year for the next 20 years, because that was -- the solar that was online in '06 they've got to pay the same amount every single year. So they're paying that billion Euros every year.

And then they brought in new stuff in 07 and 08. And so I just -- I throw out that $1 billion Euros per year because I'm contrasting it with the CSI program, which is a 3 billion per year program. And remember, I mentioned that consumers pay 80 percent of the cost of the technology. And, you know, the incentives are only designed to pay 20 percent.

And I think Julie Blunden brought up some good points earlier that I would have mentioned if she hadn't, about how they have contacted us to talk to us about net metering.

And they're looking for a way to what do they do when they get to grid parity, as well.

And that is the goal --

COMMISSIONER BYRON: Speaking of the Germans?

MS. STERKEL: Yeah, the Germans, right. The Germans and the Spanish, they both -- they want the cost of solar to come down. And we do, too. And so then what's the long-term path to keep solar installations going.

COMMISSIONER BYRON: I think we're all very fortunate to have you and your group at the PUC. We're going to make your job even easier over the next number of years, because we're going to keep writing recommendations in our policy report around distributed generation, around renewables and making the right -- and feed-in tariffs.

And you're going to keep seeing more and more legislation around this issue. So, stay on your toes.

(Laughter.)

MS. STERKEL: Thank you. And I invite the members of the listening and viewing audience to come join us at the PUC and help us figure it

out.

COMMISSIONER BYRON: In fact, you know, last Thursday we had Assemblymember Blakeslee listening in on a workshop and he ended up asking questions at the end. Maybe we should ask the webcast audience if he's on there again. Maybe he'll have some questions for you on how you're proceeding on your feed-in tariff.

Believe me, if he's there, he'll --

CHAIRPERSON PFANNENSTIEL: Molly, before you leave, I have a question that follows up on one of Jeff's.

The question on the price, he asked specifically that does the MPR make sense. The MPR is a number fundamentally driven by gas prices. The numbers being used in the European feed-in tariffs are driven on technology costs. Completely different concept. Completely unconnected to gas prices.

And so their concept, as I understood it from this morning, is frankly to promote these technologies by giving them their cost and what they determine to be a reasonable return. And then, you know, doing a 20-year payment of that.

Does that make sense to you? I mean,

does it make sense to you to do it that way to encourage the industry, as opposed to a determination of an MPR?

MS. STERKEL: I mean, you know, I think the challenge right now is that I see a big gap between what the MPR is and what they're willing to pay in Europe.

And so if policymakers and lawmakers in California are willing to make up that difference, then, you know, for example -- that's why I tried to give the example of how much higher we would have to be willing to go in order to get something close to the European feed-in tariff. I mean we're talking about paying 2 to 3 --

CHAIRPERSON PFANNENSTIEL: So, if we were really serious about it, then we --

MS. STERKEL: If we were -- if we think in terms of our overall budget priorities, as a state, that we think we can pay 300 percent --

CHAIRPERSON PFANNENSTIEL: But I don't -- these aren't tax revenues, either in Europe or here. Well, I guess in Spain they are, but in Germany and here we're not talking about tax revenues, correct?

MS. STERKEL: The CPUC doesn't have

access to tax revenues. That's why I mentioned the legislature --

CHAIRPERSON PFANNENSTIEL: This is all ratepayer money.

MS. STERKEL: For our program currently it's ratepayer money, which is one of the reasons why, you know, MPR is not exactly the same thing as the avoided cost, but, you know, it's similar.

So, yeah, I think it's a challenge. I think when we look at -- you also have to look at it in the suite of the whole RPS program. I did see in the July RPS quarterly staff progress report on the RPS, they included a chart that I believe it was made by E3, forgive me if I'm wrong, and it was looking at the future of 33 percent. And they were just looking at some, you know, rough ballpark numbers of what the RPS supply curve might look like to get to 33 percent, and what some of those cost figures might be.

And they were -- the curve goes from about $100 a megawatt hour to $180 a megawatt hour. So to translate back to the terms we're talking here, that's 10 to 18 cents a kilowatt hour.

And so certainly distributed generation

then might have an even higher price tag than that. That would be, you know, like I was saying, currently around the 22 cents to 25 cents a kilowatt hour range.

So the question is, you know, we need it all. And how much of which bucket can we afford to --

COMMISSIONER BYRON: You mean, for instance photovoltaic distributed generation --

MS. STERKEL: PV, right, I'm saying PV does -- the cost, the RPS looks like a cost curve actually including a variety of technologies --

COMMISSIONER BYRON: Right, and I believe you're correct, I believe it was E3.

MS. STERKEL: All right. And so that's just a reference point. But that did, of course, include all five technologies.

So one thing -- I'm actually surprised there's less differentiation in Europe, kind of to Julie Blunden's point about the difference between rooftop and non-rooftop. I thought her explanation was interesting in that regard. Certainly that's something that, you know, we might want to look at here as having differentiated levels, and whether or not that

makes sense.

But I don't think the PUC has a set of policy, you know, I don't think the PUC has a set policy or set answer right now. But I appreciate you trying to put me on the spot.

(Laughter.)

CHAIRPERSON PFANNENSTIEL: Thank you.

MR. LEAON: Thank you, Molly, appreciate your presentation.

I would like to ask stakeholders to hold your questions until we get to the open discussion part of the workshop. I would like to make sure that we have sufficient time to hear from Dave Hawkins, and also our panel discussion.

We're running up against time here, so I'd like to get through the next presentation, the panel discussion. And then we will open it up for open stakeholder comments at that time.

COMMISSIONER BYRON: In fact, we have a lot of folks in the audience. So if you wouldn't mind, just a show of hands, how many folks would consider themselves being from the industry out there in the audience?

CHAIRPERSON PFANNENSTIEL: Industry, what industry?

COMMISSIONER BYRON: Well, --

CHAIRPERSON PFANNENSTIEL: The solar industry?

COMMISSIONER BYRON: -- solar, wind --

CHAIRPERSON PFANNENSTIEL: The renewables industry?

COMMISSIONER BYRON: -- the renewables industry. Okay, good. Thank you. I hope we'll be hearing from some of you, as well. Then Julie Blunden doesn't get all the air time --

(Laughter.)

MR. LEAON: Okay, I'd like to introduce our next speaker, David Hawkins, Lead Renewables Power Engineer with the California ISO. And he will share a grid operator's view of feed-in tariffs.

MR. HAWKINS: Okay, let's see if I can make up some time here, too.

Basically just quickly, our particular perspective is looking at things from an operations perspective and a transmission. So, how to keep and make sure that we operate reliably. So that's our particular focus.

We don't write power purchase agreements, we don't negotiate contracts and set

prices for renewables. So we're only looking at basically the reliability issues.

When you think about the type of things we look at, it is basically looking at how to make sure the transmission lines do not sag down into the trees, the voltage stays up and we keep the voltage stable, and we operate the system within the transient stability limits. And we look at making sure there's enough transmission built and the congestion costs are manageable. Those are --

COMMISSIONER BYRON: Mr. Hawkins, you're not from the IOU, are you? You're scaring us here.

(Laughter.)

MR. HAWKINS: I'm a pure operations guy. So, our particular position is we neither support nor oppose feed-in tariffs. We certainly see that they have been successful, particularly in Europe, Spain and Canada. And certainly proposed out in Taiwan and areas in Asia.

They are certainly look like a quick fix or a silver bullet for making the increasing amount of renewables. And if the price is set right, you really get a lot of investments. If you set the price too low, nothing happens. So

pricing is absolutely critical.

And, again, our compliments to KEMA for the reports that they've been doing in this particular area that's, we think, very insightful reports that they've been producing.

I thought it would be interesting if you look at Ontario Power Authority's feed-in tariff. They set the price, they went out and they thought they were going to have 1000 megawatts over the next ten years. And they basically had everything signed up in less than a year.

At this point they pulled the plug basically on the program for larger quantities, and sort of put that into a holding pattern, although they're still doing the smaller type units. So now they're back revising the rules. We haven't seen the new rules published yet.

But sometimes if you set the price right or high, you will get, you know, many will come to the party.

Certainly Germany we've talked a lot about here today. I don't need to continue on more about Germany, but again, they basically were setting the price for the renewables approximately twice what the price was for what you pay as a

consumer. So they certainly had great success.

And Danish experiment also has been one that everybody's very familiar with. Again, you know, they've gone from very few to where if you look at the picture of Denmark today, it looks like it has measles with the spots all over the place. With huge amounts of renewables put into their systems.

All of those, you say, okay, well, how did they do it. Well, we've heard a lot about the pricing issues and what they've done to have that as part of the feed-in tariff fees.

The key thing to think about first of all with Denmark was that they really had a transmission link up to the Scandinavian countries, over to Sweden, and they really took advantage of the huge variability of the wind generation by finessing it with the hydro system out of the Scandinavian countries.

So a lot of the excess energy they have goes over there. And the hydro system ramps down. They also socialize some of it off to Germany. And just export it over to Germany, and says, here, you take it. So they have some really interesting operating issues as they've done this.

The other thing that's interesting is Europe has a lot less stringent frequency controls than we have in the United States or in North America. Our NERC standards that we have to meet for frequency control are quite stringent.

The chuckle, I guess, that we have as operators here is they were looking at the 50 hertz system in Europe, and it appears to be heading closer to becoming a 60 hertz system as we look at some of the huge variability that they have to deal with.

The other thing that's interesting is Germany, from an operator's perspective, is basically blind to what's going on with the wind generation in their area. They have no visibility of how much is going to come, where it's going to show up, what it's going to do to their system and so forth. It's all just must-take, and they just have to deal with it. And so their operators are a bit surprised all the time as to where it's going.

The one thing that they did do is because it's never evenly distributed, Germany actually has four different operating companies. And, of course, one of the companies gets most of

the burden. So they did take the advantage of taking all four companies in Germany and saying, you all share the regulation burden for making all of this work. So all of that does help.

Again, the fact that the wind patterns flowing into the wind generation areas in Denmark, Germany and Spain appear to be much more linear than some of the stuff that we see coming in on the west coast where, depending on where the jet stream goes and all that, we have much more volatility in trying to do good forecasting. We're continuing to improve our forecasting, but we've not been able to achieve the kinds of numbers of accuracy that certainly Spain has been able to do.

Another key issue that Spain found was, again they had major operating problems when all of a sudden all this stuff showed up and they had no visibility what the wind generation is doing.

They have now implemented a lot of control systems. They go back and force the wind generators to provide regulation so that they're forced to back down from their full output. So they basically turn their blades and reduce their output by a few percent so that they can provide

some ramp mitigation capability, and provide some regulation and some frequency response.

So, if you're going to implement large amounts of this, like Spain has done, you have to have a control of the system. And even if you use feed-in tariffs, it has to have some controllability back from an operator's perspective. Otherwise you really compromise the reliability.

So all of those things are really, from an operation's perspective, key things you need to think about as you implement the feed-in tariffs, and other ways of providing this large amounts of renewable.

And, of course, the other thing is that they've been apparently quite successful in getting public acceptance of wind generators, particularly in Germany and Denmark, that are spread out all over the landscape. And nobody, you know, we have not heard outcry of like, oh, my gosh, "not in my backyard". But that's a key issue if we do proliferate this a lot, is to what the public acceptance is going to be.

So, what will work in California. If we do feed-in tariffs and set the price right, we

expect that you will see a lot more installation of wind and solar. And probably a lot more in the less-than-20-megawatt type categories. I think, as a previous panelist had said, we'd like to see 1000 flowers bloom. If the price is right, you'll see a lot more of the photovoltaics and solar and various even smaller wind generation.

The fantasy, I guess, that I have is that my company will finally put canopies out in the parking lot for my car. And those canopies will have PV panels on them, so that we will see a lot more parking lots covered, as well as rooftops.

In addition, you look at things like the aqueduct, which is a huge land space, covers up a lot of land, as you see. And, of course, you think about all the evaporation out of the aqueduct. You say, why don't we cover it. And the logical thing, of course, is to cover it with a canopy with PV panels. And to go pick up that. Keeps the back of the panels cool from the water, and cuts down the evaporation. And it would be a natural use.

So, with the right price incentive, I think there are many interesting things that could

be done to really promote the increased use of renewables in California. So, all of those seem to me makes a lot of sense.

There are other things that you need to think about. A lot of this feed-in tariffs will incent, we suspect, a lot more of the development of the renewables throughout the whole distribution network.

And there's a consequence. So that distribution system was never designed for all of these types of renewables coming on, or generation all over the place.

So therefore, you look at the investments now we're going to need to make in smart grid, smart metering, so that it makes smart metering, or if not separate metering, smart metering at least so they're paid for the energy that they're going to be producing.

So if I'm going to get paid 50 cents a kilowatt hour for my PV things, you know, I really want to make sure that I'm getting that based upon the revenue meter that is looking at that.

Another concept that we'd like to promote is the idea that you're familiar with, freeway onramps. And so as you look at the

highway system around here today, you're already dealing with highway congestion and you got smart highways. And you've got smart traffic lights.

Now, all of those things help move the traffic along. And you have metering lights on the onramps. If we're going to have a lot of this stuff spread throughout the distribution system, we need to start thinking about a smart distribution system that has metering on lights. So that if we're beyond the voltage control or capacity of that piece of distribution circuit, we can say, thank you very much, but we have to have a control that would feed back to that local renewable resources to at least metering some of the stuff that's coming on.

And if that sounds way out, it probably is, because that's what some of this new thinking may have to do in order to make this work. But infrastructure development and investments in the infrastructure are critical to making this work. And investments in these types of infrastructure should go hand in hand with the development of the feed-in tariff or whatever state policies we want to implement to increase the amount of renewables.

And part of that's also going to be

looking at power quality. How much do the inverters introduce degradation of power quality, and to making sure that I'm not having power quality problems in my house due to my neighbor's PV panels or poor quality of the way that they particular work. So we've got some interesting things to look at.

The other thing we've already mentioned is the idea of plug-in hybrids. My hope and expectation is that within five years we're looking at 300,000 to 400,000 plug-in hybrids in the state. We need that kind of nighttime load to soak up some of this excess wind energy that's coming in.

And so that's a natural place to go. It would really reduce the carbon footprint. It would reduce the amount of greenhouse gases we've got. So we're very hopeful that and other energy storage is going to make sense.

As part of what we looked at also with concentrated solar systems that are coming, what we really would like to see is the thermal storage also linked up with solar, particularly concentrated solar.

So if we're going to do feed-in tariffs

we'd like to see -- I don't know whether a kicker or a bonus or something, but anyway, there should be something in the rates that would incent to make sure, incent to have that thermal storage piece as part of the concentrated solar.

And the reason that's important is because the solar will start to ramp up between 5:30 to 6:30 in the morning. The load has not yet ramped up. So you need someplace to put that energy. We don't want to lose it; we'd like to keep it. So having a system that gives us the ability to store some of that energy for the morning load pickup, and then be able to put it back into the system during the late afternoon into the evening hours would make a lot of sense. So the price has to be there to incent that extra investment.

The other thing that's interesting is we had a little discussion earlier about onpeak/offpeak. And, you know, solar meeting the onpeak. And that's true during the summer. But you have to remember in the wintertime our peak shifts to about 7:00 to 8:00 at night.

So a rooftop PV is probably not going to do much to meet that wintertime peaking period.

But we'll still get some pretty good energy during that period. So it's probably not going to help too much with the Christmas tree lighting.

But, you know, all of those things are -- the important thing is you put together this whole portfolio of lots of different renewables. The strength is, you know, we really have huge amounts of diverse resources to really meet our energy needs. So, food for thought.

COMMISSIONER BYRON: Mr. Hawkins, if I may.

MR. HAWKINS: Sure.

COMMISSIONER BYRON: The Chairman may want to comment on this, as well. But obviously the smart grid technology, those kinds of things, you know, we're all looking for additional and good reasons to implement a smarter grid.

But we're also trying to weed out the non event here, and the, I don't want this in my backyard kind of notions. The point that you made earlier about the distribution networks have to be redesigned and upgraded to handle the generation of resources. Are you aware, was that required, as well, in Europe where feed-in tariffs were successfully, and have been successfully

implemented?

MR. HAWKINS: My understanding is that in Germany, particularly, when they first wanted to build a particular renewable resource, they would simply put in the application and says, I'm going to build here. And the local utility had to do whatever it took to upgrade their particular interconnection facilities at that point to take that unit.

So, whatever it took. Whether it was on the distribution or the transmission part, my understanding was that that was the requirement

COMMISSIONER BYRON: And they absorbed the cost for that --

MR. HAWKINS: And they absorbed the cost.

COMMISSIONER BYRON: But you don't have any specifics, you just --

MR. HAWKINS: I don't, no.

COMMISSIONER BYRON: Okay, thank you.

MR. HAWKINS: Also on the electric system, in order to make this renewables work, what we are looking at, too, is the fact that we need a lot more intelligence of what's going on down in the system.

Unlike Germany, we're really looking at investments in the information systems so we have visibility. So how much is coming on in Bakersfield, how much is coming on in, you know, the San Diego area. So we would have a lot more visibility so that we can reliably operate the system. And be able to show the changes in what the loads are in those areas.

And also do a better job of linking at weather models with energy production models. So if we're going to have a lot of energy out of renewables, we'd like to make sure that the weather forecast models are helping tell us, you know, a day ahead or two days ahead, what we can expect in different areas. And then change the actual energy schedules on thermal plants and hydro plants to be able to match very nicely and make room for all the renewables that's coming on.

But the other thing then is looking at different types of storage technologies and making sure that we've got all the types of things that we can do to make it.

The other thing to recognize, I think, is that the Southern California Edison's area probably is one of the prime areas for a lot of

this major renewables. That's where most of the wind generation is going in, Tehachapi. And where a lot of the solar, concentrated solar ones are going in.

So now you say, okay, well, how am I going to move that, some of that renewables to San Diego, or move it up to PG&E or to other load centers. And obviously that's going to take some transmission planning, upgrades and so forth to move it.

One of the previous comments that we had was, well, gee, you know, we can all be absorbed in the Edison area and we'll just do tradeable RECs or something like that, so San Diego gets the advantage.

Well, you still create all the electrons in that particular area. So you still have to move the electrons whether even if you move the credits. And as we've done some of the models for some of the higher penetration levels, it's interesting that Edison turns out to be a major exporter almost 24-by-7 of some of the energy if the solar ramps up as much as we expect, or have forecasted in some of the models.

And so we're going to have to export it

to either Arizona or someplace. And so there's going to take transmission to do that. All of that, I guess, is just to say that, you know, you really have to look at the whole infrastructure of distribution and transmission to make sure that we've made the right investments to link up with all of the different types of renewable generation.

The over-supply condition is one that we continue to worry about. And, again, it's probably the feed-in tariffs, and it does a lot with wind generation, would exacerbate that to some degree.

The photovoltaics really helps a lot because it really gets into the peak periods. And, again, we're hoping that the plug-in hybrid vehicles is really going to come to the table for that.

The other thing to think about is that we're trying to get the renewable pricing to fit the load profiles. And I think there's been a lot of discussion of that. But, again, it's the idea that, you know, something that comes in at 2:00 or 4:00 in the afternoon is a lot more valuable than something that comes in at 2:00 a.m. in the

morning. So how do you make sure that fits.

And, of course, some of the stuff we saw from the biomass gives you mice, fairly flat load curves, and a nice baseload. So those are of particular interest.

And, again, if you're going to do solar, you know, obviously solar in Fresno has a lot more value than solar in Pacifica. Not to pick on Pacifica, but it's probably not the sweet spot for photovoltaics.

So, anyway, where it's at, so location's going to be important; how it fits is important; and making sure that the cost increases are bearable as we go forward.

And so the question I guess that we have is yes, we're not making probably the 2010 RPS goal; it's probably more likely 2012. All the forecasts that we have show that 2012 looks pretty reasonable and we think we're going to make it.

The transmission will be in place by then. We can move the energy. We think enough of the renewables are coming on by that time.

So I don't feel like even though the numbers have sagged a little bit over the last couple years, I really feel like the buildout plan

that is now being implemented is going to really hit the 20 percent target. So we're optimistic, I guess, it's going to be there.

The major barriers still appear to be, you know, getting the permits and getting the construction of the transmission as the major barriers. And it's not so obvious that the contracts are the barrier.

We still, even if you do feed-in tariffs, you have to do interconnection standards. You still have to look at how do you get real-time data. All the rest of the things that we need to have to make anything work is still a critical part of this. So we still have to build some things out.

And there's certainly a certain amount of complexity of trying to get the pricing set right in order to determine, you know, how to make this work better.

So I think that's my last. So, thank you very much.

CHAIRPERSON PFANNENSTIEL: Dave, before you go, just a couple quick things. First, virtually everything that you talked about had to do with problems of more renewables. I mean

nothing to do with whether that's a feed-in tariff that has caused more renewables versus all issues having what, I think, you're seeing as too many renewables without the appropriate infrastructure.

MR. HAWKINS: No, I wouldn't characterize it that way. We certainly are here to support the state's policy on integration of renewables. We're doing a lot of work to make it happen. There's a lot of things that we're working on behind the scenes. So absolutely committed to making this go.

What we're seeing is that if it's -- and so what we have is the CREZ areas that we're working on, transmission buildout to those areas. So what we have is a plan that we're executing to make all of these things go. So we do have a whole host of things in motion to make it there.

CHAIRPERSON PFANNENSTIEL: And so the question of whether or not we have feed-in tariffs are essentially -- the question is relevant to the question of how many renewables we have, I think you're saying.

MR. HAWKINS: That's correct.

CHAIRPERSON PFANNENSTIEL: But then, as you pointed out, that within the next few years we

expect or many people in this room expect a 20 percent renewables.

MR. HAWKINS: Yes.

CHAIRPERSON PFANNENSTIEL: And then there's a strong policy endorsement both on this Commission and from the Governor's Office, and from the ARB on 33 percent RPS. Not even a 33 percent all renewables across the board, but 33 percent RPS.

MR. HAWKINS: Right.

CHAIRPERSON PFANNENSTIEL: By 2020. So somehow where is this line where the ISO is comfortable meeting the reliability criteria that we have at 20 percent, but not at 33 percent? Or do you need everything that you have articulated on your slides for 20 percent? Or do you need to wait till we get to 33 percent? Where is that line?

MR. HAWKINS: Where it is today for us is we're absolutely dedicated to making 20 percent work. We are finishing all of our studies now on the 20 percent, and all the things that finally have to be done to make that achievable.

So that will be done by the end of this year. We've started work on the 33 percent.

We're engaged with the CPUC on their studies. And we're engaged with other studies with the utilities on the 33 percent.

Where -- we don't have the answers yet as to what 33 percent looks like and all the things we need to do. Our expectation is that that will become the goal that we have to meet. And our goal is to support the state policy to make it happen.

And what we're doing is to make sure that we really understand the consequences of things that we have to do. And make sure that we've got the right action plans to achieve it.

CHAIRPERSON PFANNENSTIEL: Thank you.

COMMISSIONER BYRON: I would like to also ask a question, actually maybe it's more a comment, Mr. Hawkins. Similar line to the Chairman's questioning.

I was taken, as well, by your presentation. I'm really glad to hear you say the ISO's supporting the policies because I think we all know the direction we're headed.

In fact, when I had -- a couple weeks ago I had dinner with Jim Detmers and I know this gives him apoplexy when we start talking about --

is it 33 percent RPS?

CHAIRPERSON PFANNENSTIEL: Yes.

COMMISSIONER BYRON: I thought it was 33 and a third RPM.

(Laughter.)

COMMISSIONER BYRON: So, but the only positive thing I got out of your presentation was, you know, the dream about having PV panels covering the cars in the parking lot.

I would really hope that the ISO would take a different kind of approach. And so I'll try this out on you. Because we really, we're going to take this on in the 2009 IEPR. Is how do we move towards a renewable future. How do we address all the integration issues that you're dealing with, but then there's obviously a lot more, contractual procurement, et cetera.

I prefer to see the ISO take the approach if the Europeans figured it out, so will we. And obviously they have.

So everything that I read in your presentation here kind of identifies all these problems and issues, some of which may be real, some may not. But I really think we should be taking the approach, we're going to do the same,

we're going to figure it out, we're going to get it done.

Because it is going to be tough. And it's going to be a different -- we're going to operate the grid differently, and it's going to be a different world than we're currently operating in right now.

MR. HAWKINS: Well, we agree with you. I think what I was trying to say is there's clear evidence that feed-in tariffs achieve larger integration of investments in renewables. And certainly that has been clear.

So, our expectation is that you probably are going to create such a feed-in tariff in California.

Now, the next step is let's make sure we do all the other investments that also make it work. And not keep this as a disconnected case.

COMMISSIONER BYRON: We're with you, we're in agreement. So I'll say a similar thing to you that I said to Ms. Sterkel. We're going to keep writing these recommendations, and you're going to keep seeing, and it's probably not going to make your job any easier.

But seeing as you are the lead

renewables power engineer from the ISO I suspect we're going to see you again here, and I hope we do, when we're dealing with this and putting together this policy recommendations.

MR. HAWKINS: Thank you. Well, I think we will come up with the creative ideas as to how to make it work.

COMMISSIONER BYRON: Thank you.

MR. LEAON: Okay, thank you, Dave. All right, we're now to the panel discussion where we're going to deal with really the crux of the matter today, and that's the discussion of the policy paths.

And we're going to hear from our panelists on their perspectives on those policy paths, what they can support, what they can live with.

And after the panel discussion we will have time for open stakeholder comments.

Karin Corfee with our KEMA team has graciously volunteered to moderate the panel discussion. So I'm going to yield my chair for Karin here.

(Pause.)

MS. CORFEE: Hi, there. My name is

Karin Corfee, I'm with KEMA. And I'd like to welcome all the panelists and thank you very much for coming today.

We have three key questions that we'd like to address today. And the questions are as follows: Which of the six policy paths might you be able to support and why. Which paths do you oppose and why. And lastly, which paths might you be able to live with and why.

So, we really want to get to the crux of the issue, which is how do we move forward from here. And we've taken some time to develop six policy paths, as you've learned about today. And we would like to specifically get your input on those policy paths.

We're going to take five minutes for each of the panelists and I'd like to limit that to five minutes to the best extent possible. At the end of the five minutes we'll move on to another panelist. And hopefully we'll save the questions for the after everybody's had an opportunity to present for five minutes.

Is that agreeable to the Commissioners? Okay.

And then we would also like to encourage

folks in the audience to save your questions to the end. We will have an open question-and-answer period. And we'd like to request that each of the panelists stay up here to be available to respond to questions from people in the audience, as well as the Commissioners, if that's agreeable.

So, with that, I will open it up to the first volunteer to speak. And, Dave Hawkins, I see your hand, and so this is --

(Laughter.)

MS. CORFEE: Either that, and I will introduce each person. So this is Dave from the Cal-ISO. And I think we've already done the introduction. So, thank you for volunteering to go first.

MR. HAWKINS: All right, glad to kick it off. All right, let me take them in order.

The number one option, the full market, unlimited size and so forth. You know, it seems to me that this will work. The issue for us going to be trying to make sure that the transmission --

MS. CORFEE: That's all right, keep going, keep going.

MR. HAWKINS: Number one, the full market scenario certainly will work. It's the

biggest issue is going to be making sure that we link up enough transmission, because I still think the transmission barrier will be there. And so trying to make that thing play out and get the infrastructure built out fast enough is going to be the issue.

Number two, the three-year pilot. It seems to me it's awfully short. By the time you actually get the facilities built and start to move out, I'm not sure that you would get the transmission pieces or distribution pieces built out fast enough to be able to make that work. So I'm a little concerned about that.

Number three, CREZ only. I like that one. Certainly makes us get a chance to really come out of the gates fast. And to be able to build. You know, we know where we're going, we know what the sites are. We can get the facilities built out to those sites. And we can also build the other things, too. So, number three works for me.

Number four, solar only. Yes, I guess. Solar, we could work -- the biggest thing is I would like to make sure that we get the thermal storage linked up. Or even with PV systems, do we

add enough battery storage along with those that we actually get a smoothing in power quality and so forth so that we've got the right incentives to build, you know, the technologies to work.

Number five, biomass only. No interest at all. It just seems like that's not enough. I mean I like biomass, it's great from an operations perspective. Like to see more of it. It's very distributed. It provides lots of reasons for handling waste materials. It's a great technology. Like to see, you know, lots of all the farm materials and everything else go into it. So it's fine, it probably is not sufficient by itself to meet our goals. But certainly anything to encourage biomass is fine with us.

And number six, the under-20-megawatts, sort of the 1.5 to 20 megawatt facilities, that, to us, works just fine. And basically let me put an analogy together. It's like playing in a jazz orchestra. You're going to have lots of different instruments, lots of different players. And the question is how do you really make beautiful music.

And so the question is making sure that we've got the right, you know, information systems

that we put it together, we can make the things play together, and bring the pieces together. So we think number six is something that's achievable and we think that it could make beautiful music with that.

MS. CORFEE: Okay, thank you very much. Next we'd like to have Craig Lewis speak. Craig, if you wouldn't mind introducing yourself to the group. And then we have some slides, correct?

MR. LEWIS: Correct. My name is Craig Lewis. I am the Lead for Government Relations for Green Volts. We are a solar technology company. And we have the unique distinction of being the first solar technology company to actually have a project that has successfully navigated the RPS RFO process.

And that is a 2 megawatt PPA with PG&E. It's being constructed as we speak out in Byron, California, which is not far outside of Tracy. And it will be online before the end of the year. So we're very excited about that. But we have the unique distinction there in that we're the first project through -- first solar project through. And even Julie Blunden and the folks over at Sun Power can't claim that distinction yet.

(Laughter.)

MR. LEWIS: The other thing I want to just say out of the box here is that, you know, Green Volts obviously has a customer relationship with PG&E. We look forward to many more good relationships with the utilities here in California.

And everything that I'm going to talk about today is really focused on bringing an effective policy solution to the State of California. And making sure that California has the best chance of achieving its RPS objectives, and really all of its environmental and energy objectives.

With that said, I'm going to jump here into my slides. I've just got a couple. The urgent RPS challenges that we face as a state are, first of all, hitting 20 percent of retail electricity sales by 2010. So there's been a lot of hints of 33 percent RPS by 2020, but the RPS objective we have right now is 20 percent of retail sales by 2010.

Contracts don't count. It's not 20 percent of contracted energy, it's 20 percent of online energy. So I just want to make sure we

stay focused on the most urgent objective that we have as a state.

And really, if we stay focused on that and we figure out how to solve that challenge, then it's going to guide us for the 33 percent by 2020 solution.

Transmission based on the IEPR workshop that was here some five, six weeks ago, Commissioner Byron basically concluded, and I totally agree with his assessment, that the transmission issues really are a seven- to eight-year problem. Before the transmission comes online to solve these problems, we're talking seven to eight years. That's a long ways out and something that's going to delay most of the options that were offered in the policy paths.

Also there is a significant programmatic gap in support for renewables in California. So Molly did a great job in talking about the CSI program. Obviously for 1 megawatt vendor behind the meter the RPS program is geared as defined as offsetting 500 megawatt gas turbine power plants out in the middle of the transmission interconnect.

But there is no viable support for

wholesale distributed generation, which is, by default, distribution interconnected.

So really, the main point of this is that we need to stay focused on 20 percent by 2010. And that is 20 percent of retail electricity sales. We need to make very clear that that is the definition that we need to achieve.

So, wholesale distributed generation represents a huge opportunity. And so what is wholesale distributed generation. Well, it's wholesale. You're selling electricity to a utility. It's not behind the meter, it's on the utility side of the meter.

It's 20 megawatts and under so that it can be distribution interconnected. And at 20 megawatts you can stay within the distribution grid.

WDG provides significant locational benefits value. What does that mean. That means that you're generating close to your load. David talked about the load profiles. We like to talk about load profiles because one of the important elements of a load profile is that you are generating close to your load. That increases the

value of the energy.

And, in fact, Green Volts has done an extensive analysis. We've worked hand in hand with E3 using the CPUC Commission cost effectiveness model, that basically shows, on average in California, distribution interconnected energy is worth 35 percent more than transmission interconnected energy. That is a big value boost and we need to pay attention to it.

The opportunity here for WDG is enormous. The latest renewable energy transmission initiative, or what's commonly known as RETI, report, which is the phase 1-B report, identified essentially hundreds of gigawatts -- we're not talking megawatts here, we're talking gigawatts -- of wholesale distributed generation opportunity.

What they specifically called out is 27.5 gigawatts of PV opportunity that is highly constrained. And the constraints are that it was 20 megawatt size PV projects, just PV is all they looked at, that is co-located at distribution substations, so it had to be right there at the distribution substation. And not only that, it was at a substation where there was at least 160

acres of land available that did not have an environmental sensitivity screen that would knock it out of contention.

Twenty-seven-and-a-half gigawatts with those constraints means that we're talking at least an order of magnitude bigger opportunity for wholesale distributed generation if you take those constraints off, which obviously you would. You would have a feed-in tariff that is applicable to California-wide. It doesn't have to be co-located at a substation. Doesn't have to be right at 20 megawatts.

Next slide, please.

MS. CORFEE: Craig.

MR. LEWIS: Yes.

MS. CORFEE: That's five minutes.

MR. LEWIS: Okay, I'll --

MS. CORFEE: So can we get a summary from you in terms of which policy paths you support and why?

MR. LEWIS: Yeah. Actually, I think just if you'd go to the next slide, please.

So, basically the solution is a feed-in tariff for wholesale distributed generation. What do we have to have for that to work. Well, we

have to have a rate that is fair to ratepayers and to developers. Otherwise, it's not going to work, it's not going to bring the generation online unless it's fair to the developers.

And obviously it's not going to happen with all the gatekeepers, with TURN and DRA and everybody else that's looking after ratepayers. It's not going to happen unless it's fair to ratepayers, too.

So, there's really two paths to get us there from a pricing standpoint. I really want to cover this point because pricing, I think, is something that is not well understood. And as a developer, I can shed a lot of light here.

There's two ways to go. You can go value based, which is MPR plus locational benefits. That will get us to about an 18 cents per kilowatt hour price.

Or we could go cost based. And as Molly indicated, cost is essentially somewhere in the 25 cents per kilowatt hour for solar. So if we can get somewhere in that 18 to 25 cents per kilowatt hour, we will unleash the tremendous potential of wholesale distributed generation.

I also want to note that the standard

offer must-take contract is a fundamental element to all of the successful feed-in tariff programs around the world. And it has to be part of the program here in California.

The reason being, and I can speak very authoritatively about this, there's $1 million of parasitic transaction costs that are associated with proposing, negotiating and contracting RPS deals. You cannot leverage that over small power plants -- power projects.

So, when you're talking about 20 megawatts or under and you're sucking $1 million out of that deal, and that's between the developer and the utility, if you add up all those costs you're talking $1 million got sucked out of that deal. In our case that's 15 to 20 percent, maybe more of the overall cost of that project. It's huge.

And you know, one of the things that I think came real clear in Julie's commentary is that one of the things we do not want to do is we do not want to mess around with the CSI program. Obviously Julie's very sensitive about that. And I think if you uncover her comments that was really her main point, is that leave the CSI

program alone.

And we're looking to do that. We can run in parallel by all you have to do is have a dedicated meter that serves feed-in tariff facilities. Very simple.

So in terms of the policy options that make sense to Green Volts and to the wholesale distributed generation it really is option six. That is the only one that really satisfies unleashing this market.

All of the other options, either due to timing, delaying, you know, introduction of the option until some future point in time that didn't really make sense to us, or it was the scope. Either the technology was limited, it was only solar, it was only biomass, or it was only one utility, it was pilots, volunteer.

I mean it just didn't make sense. A lot of the options didn't make sense because of the scope. So, because of timing and scope issues none of the other options really made sense to us. With some modifications, options one and four could make sense to us. And I think I'll pass the baton since I've gone over in time.

MS. CORFEE: Thank you very much. Who

would like to go next. I'm looking at Marci.

MS. BURGDORF: Okay. Good afternoon. Thank you so much for the opportunity to be here. I'm Marci Burgdorf from Southern California Edison.

And if we could go to the next slide, please. In terms of looking at all the policy options in the past I wanted to talk just for a moment about what Edison's doing in terms of meeting objectives, or contracting efforts with standard contracts.

We have an active and ongoing process. This has been discussed by several presenters and it was actually included in KEMA's draft plan.

And what we did is we looked at the market and we realized that there was a need to fill a gap. And that we wanted to capture smaller generators that could interconnect at the distribution level. And so we set up our biomass standard contracts program, which is very similar to the policy option five, which is listed in the report.

There's many elements of that contract program that are comparable to what's listed here. We do offer 10-, 15- and 20-year contracts through

that program. It's been very successful so far.

We have 11 megawatts that we've executed in terms of contracts. We have another 45 megawatts in process or in negotiations, so it definitely has worked in bringing that market forward, bringing the gap forward that we had identified.

So, it is established price at the MPR, and it's differentiated by size. So there's three different contracts depending on the size.

Some of the differences from option five is that we do have a cap limit. It is limited in terms of megawatts. And so once we hit that megawatt limit we would take a look at the program and see how it was working for us.

In terms of looking at all of the objectives listed under the report, I think they all have valuable objectives. And they all have different objectives.

And so in terms of looking at supporting versus opposed, I think that I wanted to focus more on the elements of the tariff and the design and the structure of it. I think any one of them could potentially be implemented.

In fact, policy option six is something

that we're actually seeking to do next year. We filed this as part of our RPS procurement plan. That it would extend the standard offer contract to all renewable generators.

And so it again follows this same option six policy path, but it does have limits in terms of caps. And the pricing is cost-based. And we are planning to move forward with that. It does limit it up to 20 megawatts. It does provide a floor of 1.5 megawatts.

We're also implementing the water and CREZ tariff. And that's up to 1.5 megawatts.

So, I think the point in moving forward is that any option would need to work together with the other policy objectives. Understand in the report they talked about a policy trajectory which I think is very important. And that all along we're looking at what are the barriers right now to bringing the contracts that we have in the interconnection queue, the contracts that we have under negotiation. You know, what can we do to help bring those online quicker and bring those forward before we start going out further into the markets to see what we can bring in.

The interconnection queue is congested

and we are working on that process. We are a stakeholder with CA-ISO. And we're also working on the RETI project. So we're making strides, I think, and moving forward.

And, again, so what we're trying to accomplish is, I think has to be the clear objective when we're choosing the policy objectives.

And if we could go to the next slide. In the draft report KEMA listed core elements and some noncore elements. And in addition to what they've listed as the core elements here in terms of a design, I think it's important for consideration that if we're looking at these core elements we're also looking at what kind of performance assurances can be guarantee from these generators to insure that we are moving forward, that there's sustained operation and that there's sufficient operation moving forward. That there's not stranded investment or there's something built and then left because the operator has moved on. So there should be consequences. There should be implications for project failure.

And then the other important aspect is cost recovery. And I think that that's an

important part of the framework upfront in insuring that anything we do for the benefit of the state should be equally distributed in terms of cost to everyone in the state.

Thank you.

MS. CORFEE: Thank you, Marci. Very good points. I think we'd like to move on now to bill Golove. Bill, can you introduce yourself?

MR. GOLOVE: I can. My name is Bill Golove. I'm with Chevron Energy Solutions. For those of you who are not familiar with us, we are a division of Chevron USA that focuses exclusively on clean energy projects.

Just by way of a little bit of background, Chevron has the largest exposure under AB-32, and is considering the role of renewable energy and other clean energy projects and trying to mitigate those potential liabilities. So that's one of our interests in being here.

For those of you who also don't know, Chevron is the largest owner/operator of geothermal electricity in the world. We're one of the largest solar developers in California. We have a number of biomass projects in development here. We're probably the largest developer of

fuel cells and microturbines in California. We are a large developer of CHP.

And I personally lead wind development. Right now we don't have any wind in development in California. It's kind of a gleam in our eye. Mostly because of the difficulties in getting sites, that we have any hope of getting transmission interconnection. If that could be solved we would certainly enter in California.

So, all of that said, just to quickly go through the six policy options, I think, I want to be clear. I don't speak for Chevron. I was asked to be here about a week ago, so these are really my own personal opinions as an individual business developer doing renewable projects in Chevron.

COMMISSIONER BYRON: It's too bad you couldn't have spared us the whole introduction about Chevron Energy Solutions, then.

(Laughter.)

MR. GOLOVE: You know I've got to put my plug in when I can.

(Laughter.)

MR. GOLOVE: So I think pretty clearly for us option number one where you open the whole market would be preferred.

Looking at number two, the short timeframe seems like it's going to be an unstable policy and probably would not encourage us to do anything.

Number three, I think, is discriminatory against projects that are not in CREZ zones. And again, we would probably not want to support that.

COMMISSIONER BYRON: I'm confused. You're not speaking for Chevron Energy Solutions, but I keep hearing "we" and "us". So you are speaking for Chevron Energy Solutions?

I just don't understand this kind of duplicity. So, help me out.

MR. GOLOVE: Well, I'm not legally authorized to speak for Chevron, but I am a representative of Chevron --

COMMISSIONER BYRON: Okay, nobody will sue you.

MR. GOLOVE: -- and employed by them.

COMMISSIONER BYRON: Nobody will sue you.

(Laughter.)

MR. GOLOVE: I just have to be -- I mean, I don't know if you've ever worked for a large corporation, you have to be very careful.

COMMISSIONER BYRON: No, I work for the state.

(Laughter.)

MR. GOLOVE: So you can say anything and get away with it.

(Laughter.)

MR. GOLOVE: Number four, I don't have a strong -- we or I don't have a strong opinion of that.

Number five seems too small to be significant really to us, although it might encourage us to do more in the way of biomass. But I think, from a point of view of our larger renewable interests it probably wouldn't do a lot.

And we could live with number six.

MR. KLINKNER: Hi, I'm Eric Klinkner, Assistant General Manager for Pasadena Water and Power. And I am here as a nominee, if you will, from the California Municipal Utilities Association. And I want to thank the Commission and the staff for extending the invitation to us.

Also picking up the issue of feed-in tariffs as of perhaps two weeks ago with my introduction to it. And based on what I have been able to gather, I don't believe the publicly owned

utility group, if you will, has had the time to assess feed-in tariffs or really develop a position.

What I'd like to do is make a couple general comments about things that are concerns that might work, if I may.

In general, you know, the public utilities are working diligently to cost effectively implement the loading order. You know, we're ramping up energy efficiency and demand response. We're procuring renewables largely through, you know, RFP procurement type processes. Ramping up our SB-1 compliance solar programs and so forth.

The muni community, based on my experience, has been successful with the RFP process. I can speak for Pasadena. We've done real well with even small resources down to about 4 megawatts.

But I would agree with comments already made that there's clearly a gap in getting the smallest resources and the local resources. Pasadena is about to issue an RFP for renewable resources which will be anywhere grid type. But we're asking specifically for bids within the

city. The opportunities are fairly finite there. it's an urban area, it's fairly built out. We don't know what we'll get.

So, from my perspective, the feed-in tariff is a potential opportunity to capture the local distributed generation much along the lines that Craig Lewis was saying. I think his presentation had a lot of good points.

Pricing really is the critical driver of, you know, whether or not it would be supportable or not. And not fully understanding the differences between a cost base and a value base in terms of the actual implications when you get down to numbers.

I don't believe the POU community would support it at any cost basis. I mean if cost plus meant a very very large incentive level, I don't see the municipal community supporting that across the board.

On a value basis if the number is high enough to attract the generation that you need hopefully you're not over-paying. So, again, it's a nuance which will certainly have to be looked at.

I think, you know, folks have already

raised the ratepayer issues here, and that's always a high concern with the public utilities. So I don't need to belabor that.

It did seem to be not really addressed int he KEMA report, which I think may have raised concerns amongst the people that have looked at it so far. Is this a feed-in tariff at any price type effort, or is it really going to have the cost effectiveness built into it. It's a concern simply due to its absence, I think.

There is kind of a question, I suppose, policy-wise where if the feed-in tariff structure ends up incentivizing renewable resource more than it incentivizes energy efficiency, ar we deviating from the loading order. Or do we need to further reevaluate how we incentivize energy efficiency.

Again, the key terms of a feed-in tariff are going to relate to size of the units and pricing, which will probably be very situational. Again, Pasadena, if there was a tariff design that we decided to go after, you know, biomass from dairy, it would do nothing for us. Wind, something that really tried to encourage wind wouldn't help in Pasadena.

And so we'd like to have the ability to

tweak it to the situation that best fits our customer base.

There is a little concern about potential interference with the competitive RFP solicitation process. If the standard offer tariff is so high that the competitive solicitation process falls apart, then that sort of suggests that, you know, resources we could have gotten at a better price may migrate away from us.

And also I want to go back and say that Craig hit it on the nail where the municipal community does value resources close to load. And so in the value equation it certainly does make sense to apply premium when they're close in, as long as that premium has a basis in fact and has been studied.

With all that said from my perspective, something around the range of option six is something that I would suggest we study. We will be looking at it in the context of our integrated resource plan at Pasadena.

The key question in that really would be the value -- the pricing mechanism, whether it be cost or value based. And just how big we can

handle on our system.

MS. CORFEE: Okay. Does this work? Is this working?

COMMISSIONER BYRON: The small mikes are really for the reporter. The large mikes are for the room, the tall mikes --

MS. CORFEE: Okay. Thank you, Eric. I'd like to move on to Valerie Winn from PG&E. Valerie, can you introduce yourself, and then --

MS. WINN: Sure. I'm Valerie Winn with PG&E. I am PG&E's Manager for renewable energy policy and planning.

And a lot of parties have made some really good observations here at the table today. I'm happy to say that PG&E's actually contracted with sufficient resources to meet 24 percent of our projected load in 2010. Don't actually think we'll be getting those deliveries until 2012 because of some of the issues we're encountering in the transmission and the permitting process.

PG&E does have the 1.5 megawatt public water and wastewater contract, as well as we voluntarily offered to expand that to other similarly situated renewable generators.

And we've actually received really good

public response to that. We get calls on a daily basis. And we've had at least a dozen people who have signed that contract already. And one is, I believe it's Tunnel Hill Hydro is delivering energy under that PPA. So that 1.5 megawatt contract is being very successful.

PG&E is also going to be, as part of its 2009 RPS plan, we have proposed to offer really a form contract. It's part of our protocol that we just filed in mid September. That if a counter-party is willing to accept the terms and conditions that are offered there, and at the price they bid, if once the market price referent is adopted, the price that they've bid at, at or below that level, then the contract could be considered, per se, reasonable.

We would not have to go through the extensive negotiations process or the CPUC approval process. That could actually help give generators some certainty much earlier, probably taking at least a year off of the time needed to get approvals to get started on the project.

So we're looking forward in working with the Commission on getting that approved and being able to issue that early next year.

COMMISSIONER BYRON: Excuse me, I'm sorry to interrupt. How do you characterize that, that's a standard offer, is that what --

MS. WINN: It's really, it's a form contract with our required terms and conditions from renewables proceedings, as well as with other commercial terms that we feel that counter-parties may find more acceptable than what's been included in our form contracts previously.

And we have proposed that that pilot program, and we have characterized it as a pilot, be limited to 800 gigawatt hours, which is about 1 percent of our annual retail sales. And then we could see how responsive the developer community is to that. And perhaps consider raising the cap. Or we could pursue the more formal Commission authorization of any additional contracts above that amount. So, we're looking forward to trying it out and seeing how that might work.

In many ways that's rather similar to option one that is proposed on the KEMA table, because our proposed contract is not limited by size. However, the pricing issue is quite different, as opposed to being cost based, they would need to be at the MPR or less. And we would

have a cap on the over-arching program offering.

One of my over-arching concern with all six of the options that are presented here is it's not -- none of these will resolve the transmission or the permitting issues that we face.

And what we see as even -- if someone is not in the transmission queue today, either the serial queue or the transitional queue, it's probably going to be 2017, 2019 before they are able to get interconnected to the transmission system.

And that's really an area where, I know people are looking at reform. They are making a lot of progress in that area. But I'm not certain that someone who signs a contract today is going to be willing to commit to a price that, you know, won't be effective really until eight or nine years from now.

I think generators would need more certainty as to they're going to be interconnected at a particular point so that they will know more about when they're going to start getting the revenues from the project.

Some of the other options that are presented. Not certain that the CREZ process is

fully developed enough yet that we can really make a statement that a CREZ will work. Option three is a great thing or it's not.

Option five, PG&E hasn't offered a biomass contract similar to Edison's because we have significantly, I think, a greater amount of biomass that's already in our portfolio. But we continue to work with counter-parties to negotiate and to reach an agreement that is good for both parties.

And --

MS. CORFEE: Is that it, Valerie?

MS. WINN: Um-hum.

MS. CORFEE: Thank you very much. I'd like to now move on to Laura, do you pronounce it Wisland?

MS. WISLAND: Wisland.

MS. CORFEE: Wisland.

MS. WISLAND: Yes.

MS. CORFEE: From Union of Concerned Scientists.

MS. WISLAND: Hello. I don't have a presentation. I kind of wish I do right now, since all I have is a bunch of soggy notes, but --

(Laughter.)

COMMISSIONER BYRON: Ms. Wisland, was that your bottle of water?

MS. WISLAND: No. This was not my bottle of water. If it was, I wouldn't have used the pitcher, which dumped out on me.

COMMISSIONER BYRON: I've done that, too, up here at the dais.

MS. WISLAND: Okay, I don't feel as bad.

So, thanks for the opportunity to speak today. I'm going to echo something that several stakeholders have said, which is that feed-in tariffs may be especially effective for wholesale DG because there are generally lower transmission costs. And that this has been an area that's been under-stimulated by the RPS procurement process.

And then we also feel that a feed-in tariff could be useful for emerging technologies that are making the switch from no deployment to very large scale deployment. And that this could potentially be an opportunity for them to start at a smaller scale with something that's a little bit less riskier first.

For that reason we feel that feed-in tariffs for projects that are 20 megawatts and less make the most sense this time. So we prefer

option six.

We think that the highest priority for a feed-in tariff policy should be the health developers, the team project financing, by lowering the risk and setting the stage for larger deployment to get us to 33 percent and beyond.

And I really stress that beyond point, because if we're going to meet our larger greenhouse gas reduction goals we really need to be thinking about beyond.

And for that reason we stress the need for policy stability, and worry that a pricing mechanism based on the value that's indexed to something that's dynamic could create more instability.

Let's see what else. So, again, we support option six. Where option one has a trigger that we don't really think has any benefit to developing a program that's supposedly going to be good for renewables, and then waiting to see if we fail for 20 percent.

Don't have too much of a problem with a pilot program, but don't really see a benefit to options two and four, if they only include one utility and especially if we're looking at

projects that are 20 megawatts and below.

Don't really think that limiting feed-in tariffs to the CREZ is very useful at this point. And don't necessarily think there's a reason to limit a feed-in tariff to one technology, which would be for option four and five.

MS. CORFEE: Is that it, Laura?

MS. WISLAND: Yes.

MS. CORFEE: Thank you. Sorry you have soggy notes.

MS. WISLAND: That's okay.

MS. CORFEE: I have to say, I was thinking, oh, I'm so glad that didn't happen to me.

(Laughter.)

CHAIRPERSON PFANNENSTIEL: We were all thinking that.

MS. CORFEE: And I made a mental note not to pour myself water when I'm up at the podium.

MS. WISLAND: I don't think I'll ever do that again.

MS. CORFEE: I did see how the top just popped off, though.

Next we have Andy Katz from Breathe

California. And, Andy, thank you very much for being here, and we look forward to hearing what you have to say.

MR. KATZ: Thank you. And, good afternoon, Commissioners. Andy Katz from Breathe California. We're a lung health association, so our primary lens that we look at the feed-in tariff issue is through the public health lens, concerned about criteria pollutants, as well as global warming pollution. And the need to have rapid development of renewable energy.

Watching California wait until after the deadline for the full renewables to be deployed is very disappointing. And looking towards the future we're really see the importance of reducing pollution as soon as possible. And that includes carbon dioxide as well as criteria pollutants.

The feed-in tariff promises a lot of opportunity to implement wholesale distributed generation because it can have a major benefit in terms of reducing the costs within the local grid in terms of distribution costs. It also has the opportunity to provide an immediate incentive for development of renewable energy.

When we compare -- I want to comment on

some of the things that came up in the first part, and then I'll comment on the policy paths.

Comparing the costs with Germany, I think it's important to really look at, well, how are we physically different than these European countries. We are physically different in that Germany does not get the same amount of sun.

And so when we're looking at some of the consumer backlashes that may have happened in Germany, that would not be nearly to the extent that it would occur in California because solar is just not as effective in Germany as it is in most of California. So that's really important to consider, that it's cloudy there. So we would not have that same situation here.

Also, they're more compact. And California is more spread out. And so that means we need to be very careful about considering the cost of interconnection. And right now it looks like the recommendation is to move forward with the developer being responsible for interconnection. We have to be conscious of the consequences for how does the developer perceive the costs. And how does that translate back into the price if the feed-in tariff price is being set

based on the cost of production.

So, while there's benefit, different countries have done it different ways. Some countries have said that the utility or the statewide or countrywide aggregation of the feed-in tariff customer generators will pay for the integration, for the interconnection costs. And others have gone the other way having, like Ontario has the developer paying the interconnection costs.

In Ontario it's been a big barrier. And so it's important to really learn from Ontario's program. Not necessarily to go a total 180 on that, but to just learn how can we learn from this, and identify how do we build in the interconnection issue into the feed-in tariff, either through the cost or through the overall distribution plan in California. How do we learn from that mistake that happened in Ontario through a variety of different options. So, I think that's something to consider in the future.

In terms of pricing, I think looking at the cost of production is the important thing for really integrating this. That's why I think options one and six move to the top there.

Particularly I would lean towards option six because of the distribution issues that were raised by the ISO. Not to foreclose in the future, as transmission improves, and as California gains experience with the feed-in tariff.

That looking at projects bigger wouldn't be something to consider in the future, but looking for today, it looks like option six really does make the most sense. Because you have those distributed generation benefits and those cost savings associated with the local distribution.

I also think that it's important to not have the feed-in tariff be triggered after a failure to meet the RPS goals. We really want these online as soon as possible. And not wait until 2020 to get to 30 percent. We can really go beyond by having these online earlier.

And once we get earlier then we can shoot further with the RPS. So, I would be critical of waiting for that kind of trigger.

And also, you know, I know that there are concerns about the overall cost of the entire FIT program. But, even so, having things so fixed to the RPS goal, itself, it should be really seen

as something that can be moved upward if everything's going okay.

So, if there is resistance to having an uncapped system, to really keep an open mind and say, well, 33 percent is really just the floor. Because going beyond our AB-32 goals, we're going to have to go beyond 33 percent.

I want to talk about some other considerations that go beyond the six paths. Some speakers talked about the California Solar Initiative as working really well. And some talked about it as not working.

And so I can't really comment on how that's actually working on the ground. But I do hear that people don't want to see CSI abrogated. People want to see CSI continue in place, because people have made decisions in reliance on it.

But what is important is that it not be the ceiling for incentives for solar. So we are hearing, at least to some extent, that it's not fully working, or maybe we could be doing better.

So by looking at areas that are currently served by the CSI, looking at something that will supplement, but definitely not conflict. Because I think you'll hear resistance from the

solar industry if you look at a program that would actually conflict as opposed to run in parallel.

Looking at biomass considerations. I'll say, just to disclose, I also happen to be on the board of East Bay MUD. And we had actually looked a some -- the pilot program that's currently being implemented by the CPUC for wastewater and water industries.

And our staff reported that this is not viable. We're looking at a conduit hydro program, and we're also looking at dramatically expanded anaerobic digestion for food waste.

I'll also note that doing anaerobic digestion for food waste is very important under CARB scoping plan. In the appendices they highlight that this is a very significant part of diverting, or meeting our AB-32 goals, diverting organics from the waste stream.

But there's no funding source identified. So this could be a very important way of not just meeting the 33 percent RPS goals, but also other AB-32 goals, and diverting methane from the atmosphere.

So I think it's important that biomass continue as part of option six, or whatever option

you proceed in. And to consider also the differentiation by fuel, as well as size and technologies. So when you look at biomass you're also -- the key differential is fuel.

Differentiation in solar and wind. Very very fully explored in the other countries' models. So I think there's a lot of good ideas coming out of the German and Spanish programs. And learning from their differentiation, everything from if it's on the facade versus if it's on the wall, in terms of solar PV. The geography of where wind is sited. Offshore wind, if that, you know, if that's really a consideration in California.

So that these are fully differentiated. And so I think that kind of differentiation. We shouldn't be afraid of that complexity. It's really something that's an overall benefit to managing the costs of the program.

However, there is a risk of over-differentiation. Portugal is very complex. And we want people to be able to understand this program, too.

As far as paying for it, there are some options that I think need to be weighed. One is

sharing the cost statewide, as some speakers have talked about, versus the way that the current CPUC pilot is seen where utilities have their own allotment.

I would recommend looking closer at sharing because that way if one region of the state proceeds and develops to a greater extent, that you don't have an artificial limit on development. So sharing costs statewide, I think, would prevent that kind of artificial limit in any particular area of the state.

Second, that the AB-32 process will result likely in a large carbon credit sale. And so if we're concerned about ratepayer burdens, that proceeds from that carbon credit sale may be a useful tool in mitigating that cost.

And finally, that that's what revisiting prices and digression rates are for, is managing the overall cost of the FIT program. The renewable energy is going to start out a little more expensive and then continue to become more cost effective. And so that's largely what having a periodic revisiting of prices is for. That's what digression rates are for.

So it's important to set the price

right. Don't have a price that's too low. Right now the MPR is not working for many of these technologies, so it's important to get it right in the sense of not to have the price too low that it doesn't even work.

And if you look at a feed-in tariff program, and many of the countries where it's not working it's usually because the price is too low.

And that would be my recommendation. Thank you.

MS. CORFEE: Okay, thank you very much, Andy.

Just to summarize what I'm hearing from the panelists, and I think it's somewhat unanimous, that everybody, with the exception of Valerie, I'm not sure whether or not you supported option number six, but everybody else expressed support for it.

COMMISSIONER BYRON: I heard Ms. Winn say that what they're doing is closest to option one. So I'm taking that as PG&E endorses option one, correct?

MS. WINN: Well, not the cost basis --

COMMISSIONER BYRON: Are you not speaking for your company --

(Laughter.)

MS. WINN: No, no, that was the gentleman from Chevron.

(Laughter.)

MS. WINN: No. The elements that would distinguish PG&E's pilot proposal from option one would be how the price is determined, as well as the cap. And so we've proposed an 800 gigawatt hour cap under the program, so it would not be unlimited. And we'd also propose that the price be based on what the counter-party bid into our competitive solicitation. And if it was at or below the applicable MPR for that solicitation, it would be, per se, reasonable.

CHAIRPERSON PFANNENSTIEL: So it will depend on gas prices?

MS. WINN: Well, MPR is gas prices new CCGT construction, as well as the greenhouse gas adder.

MS. CORFEE: Okay, well, that clarifies it. But I actually wanted to know about option six, as well, which is very similar to option one. The difference is that option six is 20 megawatts and below, and option one goes above 20 megawatts.

MS. WINN: Well, with respect to, you

know, the differences between a voluntary program where we have the right, but not the obligation, to have to take any contract.

Our big challenge with option six, and even with option one, is if it gives someone a put right to sell us power at a cost that is significantly higher than we would have to pay otherwise, that's not an option we are supportive of.

Also, I think 20 megawatts for a feed-in tariff is probably a bit large. We have signed many contracts throughout competitive solicitation that are less than 20 megawatts and at less than the applicable MPR.

So, if everyone is -- you know, you have a feed-in tariff that's at or even greater than the MPR, then we're going capturing those benefits for our customers, and working to manage the cost.

MS. CORFEE: Thank you for clarifying.

MS. WINN: So, something -- you know, maybe it's a little larger than 1.5, but 20 is, I think, too large.

MS. CORFEE: Okay.

COMMISSIONER BYRON: I'd point out option one is no limit. So, I mean really, except

for about four different changes, you're really not --

(Laughter.)

MS. WINN: Trying to be supportive. In a way that doesn't create undue risk for our customers. Part of our challenge was --

CHAIRPERSON PFANNENSTIEL: But I'm sorry, I guess I'm hearing that but you don't want to be required to buy. In other words, you don't want a feed-in tariff. And you don't -- you only want it small enough, and so it's not mandated. And if it's really small then it perhaps is not going to contribute to the RPS because it would be distributed generation that may or may not contribute to the RPS.

So you're not really looking for a feed-in tariff, and you're not really looking for RPS.

MS. WINN: Well, no, that's -- we proposed for our pilot program, an 800 gigawatt hour cap. And that's in the first year, no gigawatt hour. And that's equal to 1 percent of our retail sales per year.

So if we find that it's a successful program and we're able to really streamline things for ourselves and for counter-parties, that would

be a really successful outcome. And I would expect we would choose in the next solicitation to offer that up again.

CHAIRPERSON PFANNENSTIEL: For very small customers. For very small developers.

MS. WINN: Oh, no, actually there wouldn't be -- we've not proposed that in the competitive solicitations that it would be 1.5 megawatts or less. It would be open to anyone who was bidding into the solicitation who's willing to accept --

CHAIRPERSON PFANNENSTIEL: Okay, thank you, --

MS. WINN: -- the form contract that would be --

CHAIRPERSON PFANNENSTIEL: -- then, for the clarification.

MS. WINN: -- approved by the Commission. So, it actually offered greater flexibility, you know, to us as the contracting utility, to not get over-subscribed very quickly and at a high price.

COMMISSIONER BYRON: Ms. Corfee, you've been a very good moderator. These are key issues. I hope you don't mind --

MS. CORFEE: No, it's --
COMMISSIONER BYRON: -- (inaudible) --
MS. CORFEE: Absolutely.
COMMISSIONER BYRON: Ms. Winn, you said something earlier, these 20 by 1.5 megawatt contracts. You gave an example of one at Tunnel Hill Hydro. Are these procured under RFO?
MS. WINN: No. The Tunnel Hill Hydro contract is --
COMMISSIONER BYRON: No, the 20 all together. I don't want to --
MS. WINN: Oh, the under 20 megawatt contracts that we have, I think there may be about ten of them out of the nearly 40 we've --
COMMISSIONER BYRON: I thought you said there were about 20 1.5 megawatt contracts. Okay, so, please correct me.
MS. WINN: About a dozen, I believe, at this point.
COMMISSIONER BYRON: Okay, about a dozen 1.5 megawatt contracts. Are those procured through an RFO?
MS. WINN: No. That is under the 1.5 megawatt standard contract that was implemented pursuant to AB-1969.

COMMISSIONER BYRON: And these other, the 100 gigawatt hour pilot program you were discussing, these are standard offer type contracts. How are those procured, under RFO?

MS. WINN: That is part of our proposed 2009 RPS plan. The way that process works is we submit our 2009 or whatever the next year is, our proposed RPS plan. And solicitation protocol, which would include form contracts, proposed solicitation schedule.

We submit all of those to the CPUC usually in the fall. And it would get adopted in February. And we would issue our solicitation in March.

COMMISSIONER BYRON: Right.

MS. WINN: So that gives an opportunity for counter-parties to provide input to the process, suggest different terms and conditions --

COMMISSIONER BYRON: Right, --

MS. WINN: -- be modified --

COMMISSIONER BYRON: -- we're familiar with the process. And I just want to be clear. The PUC will vet that. I'm sure they will be very good programs.

But these are not anything like the

feed-in tariffs. These are contracts where PG&E is entering into through your procurement process. Very similar to the way you've been conducting business for a number of years now.

MS. WINN: Correct. And I guess what I struggle with is when I look at the feed-in tariff for 1.5 megawatts, there is a covering tariff. But the actual implementation of that tariff is through a power purchase agreement. What is attached to that governing tariff is a PPA that's legally binding on both PG&E and the counter-party.

So, to the extent that the tariff would be subsequently modified, those modifications would in no way change the existing obligations under that contract. Under one that had already been signed. They would be effective only proactively.

So it is a contractual obligation between PG&E and a counter-party. Whether it's characterized as a feed-in tariff or PPA, it --

CHAIRPERSON PFANNENSTIEL: But there is, the difference with --

MS. WINN: -- is a contractual obligation.

CHAIRPERSON PFANNENSTIEL: -- the feed-in tariff -- the difference with the feed-in tariff is that it is a must-take obligation.

MS. WINN: It is a must-take obligation --

CHAIRPERSON PFANNENSTIEL: And that's an enormous difference.

MS. WINN: -- that imposes, you know, few performance requirements, no bid security deposit, requirements on the counter-party and --

CHAIRPERSON PFANNENSTIEL: That depends on how it's set up.

MS. WINN: That's correct.

CHAIRPERSON PFANNENSTIEL: Okay. That's not necessarily the case.

MS. WINN: And what we've found in our competitive solicitations is, you know, the price is very important to the counter-party. But the nonprice terms and conditions are just as important to most of the people we've had negotiations with.

CHAIRPERSON PFANNENSTIEL: Let me just observe, and I think that there are some other specific questions, but overall, I'm sort of struck by the fact that the discussion is much

more around the value of a feed-in tariff for distributed generation. And the higher value of onsite generation. And the need, perhaps, for a feed-in tariff, or the greater applicability for a feed-in tariff.

Which is striking to me largely because we came into the question of a feed-in tariff really from the other perspective, which was the RPS. Which is larger generation and generation specifically to sell to the utility to meet an RPS requirement. And the distributed generation at the moment doesn't qualify in most cases for that.

So that really has sort of struck me that the panel, at least, seems to be observing that a feed-in tariff makes more sense for distributed gen than for central station, if you will, renewables.

Is that -- am I misreading this?

MR. GOLOVE: Can I just comment on that? I think that part of the reason for that is that, at least from my point of view, the obstacle to successful completion or development of a larger project isn't the contracting. It's other issues.

So if you change the tariff yo still have the permitting, you still have getting the

land, you still have getting the transmission interconnection that you have to deal with.

And so --

CHAIRPERSON PFANNENSTIEL: I understand, but as --

MR. GOLOVE: -- there's a certainty that you add in terms of the potential financial return by having a specific tariff. But it doesn't necessarily really resolve the more basic issues.

CHAIRPERSON PFANNENSTIEL: But on the list of reasons that the RPS was not reaching 20 percent by 2010, one of the many issues about third after transmission and siting was contractual problems in getting PPAs with the utilities.

So, part of the reason we're all here is to address that. And to say, is this a way that that one of the many barriers could be overcome. And instead, I think that this -- and I think very positively this discussion has sort of morphed into a completely different discussion, which is more about, well, gee, here's another use for a feed-in tariff that is probably more valuable.

But I don't want to lose that first question. Would a feed-in tariff be helpful. It

won't solve all the RPS problems, I stipulate to that. But would it be helpful in that regard.

And I really haven't heard conclusively that it would.

MR. GOLOVE: Well, I would say that it would definitely be helpful in that it would give you a kind of financial certainty which you don't have right now.

We go into contract negotiations with a utility without knowing kind of where we're going to end up. So there's a lot riding on it at that point.

If we knew that we were shooting for X number of cents per kilowatt hour, we would be able to screen our projects much earlier in the process.

So it would definitely help for development of the larger projects.

CHAIRPERSON PFANNENSTIEL: Thank you. Ms. Winn, let me go back and ask you a followup question to something that you had said.

You commented that while PG&E wasn't going to make your RPS target by 2010, that you, in fact, had contracted for, I think you said 24 percent by 2010.

Do you have a sense of, if I might ask, what percent will you have actually under construction by 2010?

I guess our issue here has been there's been such a very high percent of contract failure on the renewable projects. So we've really had no confidence whatsoever that contractual amounts were anywhere near the same as delivered energy. And perhaps if you actually have something under construction, that's a little closer.

MS. WINN: Certainly we have several projects that are under construction. Some that are in the permitting process; some that may still be seeking site control. So I think all of these developers are in different areas.

As we've noted when we've been here at the CEC previously, some of our key concerns are ITCs still haven't been extended yet. And that is a critical concern for some of these --

CHAIRPERSON PFANNENSTIEL: Well, I stipulated to the fact there's --

MS. WINN: -- these developers.

CHAIRPERSON PFANNENSTIEL: -- a whole list of other barriers.

MS. WINN: Yeah, there are a whole list

of others.

CHAIRPERSON PFANNENSTIEL: I'm not asking you to work your way through all the barriers. The contractual ones is the one that I was actually raising. So, thank you.

MS. WINN: Right. And the transmission delays, as well, may -- people are seeking their permits, but can also delay actual construction.

MR. LEWIS: Can I relate something here with respect to the 20 megawatt size and the standard offer must-take contract.

I had the pleasure three weeks ago of spending a full day with Jim Detmers, who, for the folks in the room that are not familiar with Jim, he is the VP of Operations at Cal-ISO, and ultimately the guy responsible for keeping the lights on in California.

And basically, a week before meeting with Jim, I had had a conversation with David Hawkins here at a CPUC proceeding. And talked about feed-in tariffs and where was that cutoff where you could do a must-take contract without having any issues on the grid, on the distribution grid.

And David said, well, I'm certain that

below 10 megawatts, not a problem. And so in the discussions with Jim Detmers we talked about that 10-megawatt and 20-megawatt, you know, kind of in between there.

Jim basically said, 20 megawatts, no problem, anywhere in California. The problem you're going to get, there's no technical problem. The problem you're going to get is you're going to get resistance from a utility business model that currently has control of that. They control what they take and what they don't.

So, you know, obviously anybody on the utility side of this discussion is going to have some resistance here. It's understandable, right. That's part of their business model, that's part of where they get the leverage in the negotiations.

But, talking from a technical standpoint, there is no issue there. And that's basically reaffirmed by Jim Detmers at Cal-ISO.

So I really encourage that he get brought into this conversation.

COMMISSIONER BYRON: That's excellent, thanks. Good addition. And that also means that we can ignore the bullet in Mr. Hawkins'

presentation that a system integration study for anything over a megawatt isn't necessary, then.

I'm being facetious. It's just that everybody's covering themselves here and that's what's making this a little bit difficult. I think we should turn it back over to Ms. Corfee and see if she can close up our panel.

MR. TUTT: Well, before you do, I think Mr. Hawkins cites that anything over a megawatt connected to the transmission system. I don't know that he has the same concern about something connected to the distribution system.

MR. HAWKINS: Anything really less than 10 megawatts requires almost no study at all. It's a pro forma thing we go through with the small generator interconnection process.

MS. CORFEE: All right. So, are there any other questions from up on the --

CHAIRPERSON PFANNENSTIEL: Yeah, let me just ask one of Ms. Burgdorf. I think we heard very great concern from PG&E about essentially any of these options because they would be a must-take requirement.

Yet, as I remember, you said that Edison could actually work across any of them if they

were properly structured. Does properly structured mean as long as they don't have a must-take option, must-take requirement?

MS. BURGDORF: Well, I'd say we're certainly more in favor of moving forward under an option seven, where we are maintaining a status quo and we are allowed to move forward on a voluntary basis. I think that's also another option --

COMMISSIONER BYRON: I didn't see option seven on this.

(Laughter.)

MS. BURGDORF: Well, it wasn't listed on the chart, but it was included in the report. I think we would be in favor of that, as well, because I think what, you know, trying to demonstrate, is that we are taking action moving forward, trying to identify the gap. We are developing standard contracts. We are working with small generators. We are trying to do everything we can to help bring these, you know, this level of projects and contracts into the system.

So, I think my point is in terms of a must-take, we certainly don't want to revisit a

PURPA obligation where we ran into over-subscription and, you know, the other lists of problems.

And so I think that there is a way that we can -- it's possible if there is a way for us to balance that. What we're looking at, what works best for our utility. I'm not sure that that makes the most sense for another utility.

You know, we're trying to build out our Tehachapi transmission buildout. So, for us there is a genuine interest in having resources spring up in that area. And if there is, you know, if there's something we could do to move that forward, I think we would consider that moving forward, as well.

I'm not sure that that makes sense for, you know, another IOU or LSE.

COMMISSIONER BYRON: If I could just -- my other questions were for Ms. Burgdorf, as well, but I think instead I'll just summarize my take from this.

You ladies are representing your companies well here, but I don't think it's lost on us or the others that are here, the real impediment to the notion of a feed-in tariff is

from the investor-owned utilities at this point.

And, you know, standard offer contracts moving forward with biomass, these are all good things. But we're still only talking about 11 megawatts of biomass at this point.

We're looking for a big infusion of renewables, and we're looking for some movement on the part of the utilities for a solution. And a must-take is going to be among the characteristics of a feed-in tariff.

So, I'd really like to see the utilities, instead of trying to put lipstick on a pig here, really try and take the approach that we've recommended to the ISO. You all say we're moving to higher renewables, let's not obfuscate. Let's say we're going to get there.

And that's what we need. So I really hope you'll participate in our IEPR process. And I'll try and refrain from making comments like lipstick on a pig.

(Laughter.)

MS. WINN: Actually, thank you for the feedback. And we're certainly hoping that our program this year will be successful.

But one of our concerns with the feed-in

tariff and the discussion focusing on the IOUs is that it would be applicable only to the investor-owned utilities.

And as we talk about moving to 33 percent, we've certainly emphasized that there needs to be a level playing field in the state where --

CHAIRPERSON PFANNENSTIEL: I'm sorry, where did you get that it would only be applicable to the investor-owned utilities?

MS. WINN: That certainly, when you look at some of the pilot programs that have been proposed for IOUs, or just from my sense --

CHAIRPERSON PFANNENSTIEL: But certainly the --

MS. WINN: -- the general --

CHAIRPERSON PFANNENSTIEL: -- legislation, for example, or if it was something that the Energy Commission recommended to the Legislature and the Legislature then adopted, I don't understand why you would think that.

So, PG&E would be okay with a feed-in tariff with a must-take obligation as long as it was applied equally to he publicly owned utilities? We can quote you on that?

COMMISSIONER BYRON: I don't think so.

(Laughter.)

MS. WINN: Well, I guess when I hear must-take and I don't hear a cap, can't say that I think having it applicable to everyone would certainly be a positive step. Would we want that to be the only tool we have to contract with renewables, I don't know.

COMMISSIONER BYRON: This is part of the issue that I brought up earlier in the day, at least for me, how everything is framed in the context of what serves the investor-owned utilities needs.

I'd just like to make a last comment, if I could, to Mr. Klinkner. I hope this is encouraging to you. You do not have to follow the lead of the investor-owned utilities --

(Laughter.)

COMMISSIONER BYRON: -- nor the PUC. You could actually get it right before, or you could follow and get it right after, but we're also counting on the publicly owned utilities to look at this in a totally different light.

And I notice some of your comments seemed to be framed in the same context of

regulation of the IOUs. You're not obviously under that same rubric.

But the state will, of course, expect, as Ms. Winn pointed out, we will expect to see the publicly owned utilities step up here, as well, on the renewables.

So, I hope you get it right.

MR. KLINKNER: We'll certainly do our best to get it right. (inaudible) it's something we are considering is in the context of our whole resource portfolio, and in the context of the fact that particularly in the distributed generation aspect, we have infrastructure problems which perhaps not be resolved, but mitigated somewhat by having more in-town generation.

You know, I think that the public utilities, in general, don't understand a lot about this and certainly would be as resistant as anyone to the perception of having it forced down their throats with terms that they don't like.

But that the community needs to really evaluate it and understand all the aspects of it.

CHAIRPERSON PFANNENSTIEL: Let me just say that the State of California has determined that 20 percent, at this point, of our electric

sales from the state should be renewables by 2010. And is considering 33 percent. So it is, in fact, a public mandate to go to the 20 percent, and perhaps higher.

So I think that the policymakers have spoken in California. And with AB-32 there's a lot of reason to believe, in fact, that we have committed ourselves on a path that is beyond that.

So I think that what we're all here doing is looking for the how to do that. And the not why can't we do it.

MR. KATZ: In addition, the draft scoping plan specifically did include municipal utilities, public utilities, in addition to investor-owned utilities in the assessment of the 33 percent RPS.

Although the scoping plan didn't directly discuss feed-in tariffs, there was a discussion of this. And there are some comments on file with the ARB, as well.

CHAIRPERSON PFANNENSTIEL: Ms. Corfee, anything left for the panel?

MS. CORFEE: Yeah, what I'd like to do is just allow the panel members one final opportunity to comment after hearing the feedback.

And then open it up to stakeholders in the audience, anybody that has comments, to have an opportunity to come up to the podium.

It is 4:00. We were scheduled to adjourn at 4:00. And, you know, with your patience I think it's important that we do allow folks --

CHAIRPERSON PFANNENSTIEL: Certainly you have our patience for the time being. But I would ask all parties, at this point forward, to really be respectful of the time and try to keep any further comments succinct.

MS. CORFEE: Okay. So, any final comments from members of the panel? No?

MR. LEWIS: I have one quick thing that's been burning on me since we talked about the German feed-in tariff. And that is that somebody had quoted a $1 billion cost. But the way the Germans evaluate their actual total, all-in cost, is they also consider the benefit by reducing demand on natural gas and other fossil fuels, how that reduces the price of those feedstocks and energy generated from those feedstocks.

And so when Wilson Rickerson talked

about a .1 percent, that is a very sophisticated analysis that incorporates the benefits of reducing demand on those other fuels. And the benefits that everybody else that's buying at the 95 percent level, whereas they would have been buying at the 100 percent level benefits because that price gets brought down.

So, it is a really important feature that got missed over today. And just want to make sure that that is in everybody's mind, as well. There's a huge benefit to bringing the renewables on in a big way.

CHAIRPERSON PFANNENSTIEL: Thank you.

MS. BURGDORF: I just wanted to comment, as well. You know, Edison is committed to meeting the 20 percent goal. You know, we're committed to going beyond the 20 percent goal. We're not looking at it from a perspective where we procure up to 20 percent and then we stop. We have ongoing annual solicitations. And that continues to be our preferred method of contracting, as it is the state's stated policy preferred method, is the competitive solicitation process.

COMMISSIONER BYRON: Whose stated policy?

MS. BURGDORF: The stated policy of California, the preferred method to bring RPS projects is a competitive solicitation process.

COMMISSIONER BYRON: Okay.

MS. BURGDORF: So we are very active in making that very successful and doing whatever we can to bring more renewables online and fill in the gaps.

MS. CORFEE: Okay, with that we're going to open it up to public comment.

MR. LEAON: Thank you, Karin. We have a couple of blue cards. David Townley, Vice President of U.S. Sales and Marketing, Infinia Corporation.

MR. TOWNLEY: Thank you, Commissioners, for the opportunity to speak to you today. My name is David Townley; I'm with Infinia Corporation. Infinia is a Kennewick, Washington-based manufacturer of a 3 kilowatt ac electric concentrator dish engine solar electric system.

We currently employ about 120 people in the Washington area. We're expanding our U.S. sales and service operation here in southern California.

Infinia will be shipping its commercial

Infinia solar system beginning in January. Currently has contracts for 77 megawatts delivered next year in projects of 1 megawatt and larger.

Infinia believes implementing option six could work, depending on the final solar feed-in tariff rates and other details, of course. But it could work to bring Infinia's technology into the renewable energy market.

Expanding option six to larger projects could be done anytime by this Commission, the PUC, whenever you deem it appropriate. And we would welcome that expansion.

Infinia believes that over the next five years with a 30 percent ITC we should be able to get down to costs that would intersect an MPR-type structure. But getting from here to there is the issue. And annual sales growth is what helps get us there.

Immediate implementation of option six would help bring Infinia and other emerging solar and renewable technologies into the market. And its risk for overpayment, we believe, is attractive. It's risk for overpayment, excuse me, can be managed. It's not so large that it can't be managed. It's a contained system.

Again, larger megawatt projects can continue to be RFP-based, but could be offered a feed-in tariff option, option one, when more experience with option six guides the implementation of those larger systems.

Thank you for the opportunity to comment. Certainly answer any questions you might have.

COMMISSIONER BYRON: Thank you for coming.

MR. TOWNLEY: Thank you.

MR. LEAON: Okay, our next speaking request is from Tom Faust, Redwood Renewables.

MR. FAUST: Good afternoon, Commissioners and Staff. My question is directed to Marci, Southern California Edison.

It's my understanding that you have a feed-in tariff on file with the state, to bring on around 750 megawatts of power. At the same time you are trying to, or you just said you had contracted for 20 megawatts in one unit, one 45 megawatts at a market price referent. And I assume that's anywhere between 10 and 15 cents.

At the same time you have on file a feed-in tariff that you're requesting 47 cents.

And I didn't -- I've done the math, as I'm sure most people have. And if you put in the projected ITC that would give a return on investment of something like around in three years for a 47 cent tariff and for 750 megawatts.

Can you please explain why you think you're entitled to 47 cents whereas other people are only entitled to around 9 cents and 10 cents a market price referent? It seems to be a huge discrepancy that doesn't seem justified.

You know, what's good for the goose is good for the gander, you know. You know, if you have people in your territory that have rooftop installations, it seems to me that they should be entitled to the same rate of 47 cents. If you feel that you're entitled to 47 cents a kilowatt hour, under a time-use basis, that your customers should also be entitled to the same rate. Rather than just trying to contract them and keep them at 15 and 16 cents.

And the same thing goes for PG&E who seems to be in the same area. Thank you.

MS. CORFEE: So, Marci, do you want to take a stab at that?

MS. BURGDORF: Sure. I think you're

referring to the 250 megawatt solar PV application that --

MR. TOWNLEY: It's a total of 750 --

MS. BURGDORF: -- that we've got?

MR. TOWNLEY: -- if you add up all the incremental. There's 250, then there's another 250, then there's another -- you add it up, it's 750.

MS. BURGDORF: Okay. Well, I guess the initial application that was filed was for 250 megawatts; it's a solar PV utility-owned generation that we have recently filed.

You know, this project was developed to meet objectives of the CSI, not developed as an RPS program. It was not developed specifically for us to contribute to the RPS goals.

And while the project will, because it will be generating electricity from solar PV, the objectives in mind were designed for it to further the objectives and goals of the CSI program. And to further the solar PV market.

So that's really the sole purpose in the application. I --

MR. TUTT: Marci, can I -- I mean I understood that project to be outside of the CSI.

So, I just want -- I'm confused by what your stating.

MS. BURGDORF: Right. In terms of it contributing to the CSI, it does not. But I guess what I'm saying is that it meets the objectives of the CSI, which is to further the PV market and to actually demonstrate PV in the commercial market. And that was the idea behind that program.

COMMISSIONER BYRON: Really? A 750, what is it, 750 --

MS. BURGDORF: It's 250 megawatts.

COMMISSIONER BYRON: No, no, no, the total price was initially announced at a billion. And I haven't done the math recently, but it's much greater than that. It's much greater than 250.

MS. BURGDORF: Well, the application that I know of is 250 megawatts that was submitted to --

COMMISSIONER BYRON: All right, we'll go with that. A $250 million demonstration in the PV market, is that what you're saying?

MR. KINOSIAN: It's 250 megawatts, it's about 800 million.

COMMISSIONER BYRON: Yes, that's more

like the number, 250 megawatts at about $800 million.

MS. BURGDORF: Okay, yeah, sure. Let me jus clarify that, I don't have -- I was not part of the application process in terms of this program. It was developed through our generation group, through utility-owned generation group. So it was designed, from a business perspective, to look at utility-owned generation.

COMMISSIONER BYRON: Right, and it was done outside of the procurement process.

MS. BURGDORF: There was a procurement process, I believe, for the solar installer.

COMMISSIONER BYRON: Mr. Faust, your comments are well taken. I'm not sure we're going to be able to get to the bottom of it in this particular workshop. But these are the kind of discrepancies this Commission is concerned about.

MR. LEWIS: I might be able to shed a little bit of light on it, I'm pretty familiar with the application.

The --

COMMISSIONER BYRON: Did you submit a proposal?

MR. LEWIS: No, no, --

(Laughter.)

MR. LEWIS: -- Green Volts did not.

COMMISSIONER BYRON: Because you couldn't disclose that if you did, you know.

MR. LEWIS: Okay, well, we didn't, so --

(Laughter.)

MR. LEWIS: -- we didn't.

COMMISSIONER BYRON: You know, what I'm referring to, -- is laughing over here. Did you see the letter that Fong Wan sent from Mirant two days ago?

You might want to get your hands on that. Do you know what I'm talking about, Ms. Winn?

MS. WINN: I've seen the letter. I've not read it --

COMMISSIONER BYRON: Yes.

MS. WINN: -- in detail.

COMMISSIONER BYRON: PG&E put Mirant on notice that they signed a nondisclosure agreement when they submitted their proposals as part of their solicitation. And here they end up in the press about it. And they were put on notice that they may not be selected now as a result.

And I think it puts everybody else on

notice, too. If you participate in our process keep your mouth shut.

MR. LEWIS: Well, we did not participate in the --

(Laughter.)

MS. WINN: Although, Mr. Lewis has participated in our RPS solicitations --

COMMISSIONER BYRON: You shouldn't be disclosing that --

MS. WINN: No, but it's public knowledge because he has signed a contract with us now.

COMMISSIONER BYRON: That's right, once you sign --

MS. WINN: So now it's public.

COMMISSIONER BYRON: -- a contract you're okay. Again, this is my point about how this is all being done to the benefit of the investor-owned utilities. And I don't see how customers' interests are served with this.

So I'm sorry to digress here, but you go ahead and make your point, Mr. Lewis.

MR. LEWIS: You know, on that point before I get to my Edison point, you know, California is governed by a regulatory compact, which is you have monopolistic businesses that

have agreed to basically be regulated by an entity or entities that are looking out for the better interests of California.

So, really, it comes down to the regulators have to step up and just make sure that the right policies are put in place. So I hear your pain; I think the utilities are, you know, they're looking out for their best interests and the best interests of their shareholders. And it's the regulators that really have to step up and make sure that we get, at the end of the day, we get some really quality policy put in place in California.

So, with that said, I won't disclose anything about our agreement with PG&E. But I will talk about the SCE solar PV program application.

Basically that's priced at about 30 cents a kilowatt hour for the first, in the first year. And that 30 cents a kilowatt hour does not get any advantage of the federal ITC because there's an exclusion for utilities.

So, basically Southern California Edison has found it to be fit to have the ratepayers pick up a cost that comes out to 30 cents a kilowatt

hour. Which I think is informative, given that all the pricing we've talked about today has ranged essentially from 18 cents on a pure value base for wholesale distributed generation with locational benefits value, which are quantifiable and tangible. Up to about 25 cents per kilowatt hour, which is what Molly Sterkel had mentioned, is what you need to really energize the solar market here in California in the WDG market segment.

And then here we've got 30 cents. Now, Edison has to be higher than that typical 25 cents because they don't get to take advantage of that 30 percent ITC.

So that means that they have found it fit to basically be the developer, even though that that would put essentially 30 percent of the deal null and void, and take away that benefit from the California ratepayers.

So I think that that's informative that 30 cents has been justified in an application that's been submitted by a utility, and it's a number that we should be taking a close look at.

MR. LEAON: Okay, we did have some earlier speaking requests on Molly's presentation.

Unfortunately, Molly had to head out, so we'll just table those requests.

MR. CHADIMA: I'm one of those and I'd like to make a comment.

MR. LEAON: All right, okay. We have, are you Steve?

MR. CHADIMA: Yes, I am.

MR. LEAON: Okay, Steve, come on up. And name and organization.

MR. CHADIMA: Good afternoon; my name is Steve Chadima and I'm with EI Solutions and Energy Innovations. We're a CPV developer and also an installer of large commercial systems.

And I wanted to clarify a couple of points that Molly was making with regard to the existing feed-in tariffs, particularly the AB-1969 tariff.

The reason why third parties are not allowed is because there is specific language in the legislation which requires the agreement to be made between the utility and the customer of the utility. So that's something we're trying to fix, so set that one aside.

As to why no one is taking anybody up on these offers, PG&E has indicated that there are

some takers. I don't believe any of those are solar projects. And to my knowledge there are no solar projects. And the reason goes right back to the question we're here to discuss today, which is the -- which point of reference to you use in setting a price point for these tariffs.

So, as several people here have mentioned, when you use the market price referent as the base, if you don't acknowledge the additional contributions such as the locational benefits that Craig described, or the time of delivery kickers or adders that were discussed, then you can't make these projects work.

Unless you take the opposite approach like the German approach, where you look at what is it going to take to actually get these projects done from a return basis.

But on the assumption that the point is to get these assets in place at the lowest possible cost to the ratepayers, then going the cost-up approach or the MPR approach makes sense. But you have to include all these other things.

And to your specific question about the time of delivery, the adders -- and Edison actually has the highest adders, they're up to 3X

the MPR for weekday afternoons during the summer. So no holidays, no weekends, you know, these are very very finely tuned contracts in that sense.

We do these projects. In fact, we do them for wastewater treatment facilities and water districts. And we can't make these things pencil out as they exist. Even with these time-of-delivery kickers. We can't make them pencil out at these particular prices.

And I think with regard to one other thing. I'm also the Chairman of the Solar Alliance that some of you know. The Solar Alliance is an association of the largest, all the largest PV manufacturers, the largest installers and the largest financiers. There's 30 of us in this group.

And if we were to have been asked which of these six alternatives we would support, it would be option six. We believe that the CSI has a place under the net metering cap, that above 20 megawatts and really in deference to getting the most value for the ratepayers out of these contracts, negotiated contracts, would probably be the best way to go.

But this gap in the middle, particularly

those systems that are connected within the distribution system and not at the transmission level, this feed-in tariff seems to make the most sense.

And I realize, Commissioner Pfannenstiel, that you specifically started this process looking at much larger projects. But I think the industry has finally come down to the point where we feel as though this trifurcated approach where you've got the net metering and a declining set of incentives for customer-sided systems under the net metering cap, whatever that cap is, if it grows to 2 megawatts or it stays at 1 to 20 megawatts makes sense for a feed-in tariff. And then above that makes sense for contracts, negotiated contracts.

CHAIRPERSON PFANNENSTIEL: That perspective was very helpful. I appreciate that.

MR. CHADIMA: Thank you.

COMMISSIONER BYRON: Yes, Mr. Chadima, before you leave, a quick question. Thank you, that was extremely helpful. And, you know, the fact that all these detailed contractual aspects of the payment, and I'm glad to see the 3X in there. But, like you say, it's all narrowed down

and you can't make all this pencil out.

What about Mr. Lewis' comment earlier, at the beginning, about the million dollars. We say these little projects have a lot of hair on them. They have as much hair on them as the big projects.

A million dollar kind of development cost associated with these one or two megawatt projects really aren't even considered in either by anybody. How does that --

MR. LEWIS: Transaction costs.

COMMISSIONER BYRON: Transaction costs, I'm sorry. Would you explain the transaction costs just briefly so we don't misunderstand?

MR. LEWIS: Proposing, negotiating, contracting.

COMMISSIONER BYRON: Yes, right. From start to finish to get in place. Was there a comment on that?

MR. CHADIMA: Yeah, we agree. Just leave it at that, we agree. It's maybe there are not quite as many costs for smaller contracts as larger contracts. But it's not dramatically different. And I think if Craig's calculations are a million bucks, even if he's off by 10 or 20

percent, it's still a huge amount -- a huge percentage of the total contract benefits, basically.

MR. LEWIS: And that's not based on our contract with PG&E --

COMMISSIONER BYRON: Understood, I understood that.

(Laughter.)

(Parties speaking simultaneously.)

MR. CHADIMA:: Make sure he's not revealing any inside information here, so -- you might get one of those letters from PG&E. So, thank you very much for the opportunity.

MR. LEAON: The next speaking request is from Misti Norton, VP Sales, ET Solar.

MS. NORTON: Hi. I'm Misti Norton with ET Solar, a manufacturer. I just wanted to say I really like Jeffrey to make the comment to encourage thinking beyond regulations. Because I think we really need to do that to successfully move forward.

Just a few things I'd like to point out that I think everybody knows, is that we need power in the State of California, and we need jobs in the State of California. And growing our solar

industry will get us both.

The price that we're asking for for a feed-in tariff to make it make sense financially, so the solar industry could grow, could be as much as 30 cents today. But these are on 20-year contracts. So there is a time that that should break even and maybe even be beneficial to the utilities.

We can't concentrate on the 30 cents today. Let's look at the 30 cents 15 years from now and see how the cost balances out.

So I think we're just concentrating on something that's going to change drastically.

If the utilities were forced to build power plants it would cost them a lot more than 30 cents feed-in tariff. They'd have to go out and get loans; they'd have to build these power plants for the energy.

Basically we're building and spending our money to build these power plants for the utilities. We shouldn't do it for free. We should get a profit for it, just like any other investors out there. And so I think that really needs to be looked at, also.

I was in Germany recently at InterSolar.

A gentleman made a comment within the industry in Germany, he said the difference between the industry in the USA and in Europe is in Europe the solar industry is structured to make money, as an investment. In the United States it's to save money. So they're not -- you know, why would you be interested. It's an investment.

Would you invest $20 million to save money? No, you invest $20 million to make money.

That's it.

MR. SPEAKER: Good point.

MR. LEAON: Kelly Desy, Government Program Specialist, Sol Focus, Inc.

MS. DESY: First of all I'd like to thank you all for your time and patience today, and for opening up this dialogue. I'm Kelly Desy; I work with Sol Focus. We are a concentrator photovoltaic technology company.

You heard from my colleague, Warren Nishikawa, on Monday during the Senate Bill 1 hearing. We recently were listed on the California Energy Commission's approved equipment list as the first CPV technology there.

I'll keep my comments brief today, and will go in more detail in the written comments.

But answering some of the questions put forth that were asked, Sol Focus would support number six, as they feel that it really hits their current gap, as you've heard today.

As well as supports distributed generation, which is scalable. I think that's a word that we haven't heard yet today. And is a very important word to keep in mind. Scalability of these technologies that can be scaled up or down.

One of the potential limits that I see under option one is the limit for emerging technologies, which I think are going to be an important piece of meeting RPS goals in the future.

My colleague at Green Volts says, as well as from Infinia, our technologies are emerging, and they are becoming proven in other countries such as Spain.

One thing that I didn't mention at the onset is that Sol Focus does have half a megawatt generating electricity in Spain. That was part of the public/private partnership, the ISFOC project, which was truly enabled by the feed-in tariff there in Spain.

So that was very effective in attracting investment dollars to those projects, which really enabled that to happen. And so the ISFOC project was in partnership with the government of Castilla La Mancha there. So think it's important to keep in mind that these feed-in tariffs can enable those type of projects and help us meet our policy goals.

Looking at the current California feed-in tariff, we've done a lot of looking at that. And just at the current levels, I think we've heard it mentioned here today, the market price referent just really isn't quite meeting the needs for solar. Which is why we don't have the solar contracts under the current California feed-in tariff.

Really the economics just aren't there. And a lot of our customers who are talking to us, looking at this new technology, is that the California Solar Initiative is more attractive at that 1 megawatt level. It's limited and it still be that way at a 1.5 megawatt level. So, just to keep in mind that.

Other than that, thank you.

COMMISSIONER BYRON: Very good comments.

Thank you for coming.

MR. LEAON: I have one more speaking request, Chip Bissell, Operations Manager, Silverwood Energy.

MR. BISSELL: Hi, my name's Chip Bissell. I work with Silverwood Energy, which is a system -- solar and fuel cell system installer, based in San Diego and opening up here in the Bay Area. We actually work with a number of the larger companies who I don't want to mention here, in the trenches, doing the installations.

My comment is simply that from our perspective, in terms of obtaining panels and being cost competitive, and fulfilling kind of the tenets of the CSI, whereas the price of materials is supposed to decline, the CSI follows along with it. Simply, it's an untenable situation for us.

We're paying more now for steel, more for wire, more for panels. We can't compete against the Europeans for panels. We're looking at panel availability next year, and panel pricing next year that is going to make life very difficult for us.

So, as far as we're concerned the CSI right now, as well as it's supposed to work, is

sort of blocking up the way the financial system is blocking up on a macro scale. And it's just making life very difficult for us.

Thank you very much.

COMMISSIONER BYRON: Mr. Bissell, could you go into a little bit more detail? This is important. You said we can't obtain the same costing as the Europeans are getting. Is it anything technical here? Is it something to do with our interconnection? Is it something to do with our UL label rating? What's the difference?

MR. BISSELL: It's simpler than that. It's the value of the dollar against the Euro.

COMMISSIONER BYRON: Ah, yes.

MR. BISSELL: And it's the demand for panels over in Europe and Asia that is really, as it's been pointed out today, you know, people over there are simply willing to pay more for the panels than we are. We cannot afford to compete.

It's about at least $1 per watt differential that we face. So, that's what we're up against.

COMMISSIONER BYRON: Thank you.

CHAIRPERSON PFANNENSTIEL: Thank you.

MR. LEAON: I have no more speaking

requests in the room. And I was going to ask staff if they would check on the -- if we have any WebEx requests.

MS. SPEAKER: We can unmute it right now, but there hasn't been any.

MR. LEAON: Okay, go ahead and unmute the phone lines.

MS. SPEAKER: Okay.

MR. LEAON: Do we have any stakeholders on the phone that would like to make a comment at this time?

Okay. Any concluding remarks from the dais?

CHAIRPERSON PFANNENSTIEL: I do. I want to say thank you to the panel and to the other stakeholders here.

I think we've learned a lot. And I think we've come through -- I want to thank KEMA, good report -- and the staff, together -- good report, but I think that this discussion today has helped more than the report, itself.

I think we kind of peeled back some of what have been issues that have concerned us, and that we've been struggling with.

So, thank you for your long attendance.

Commissioner Byron?

COMMISSIONER BYRON: One last thing I'd also like to thank the folks from the PUC, in particular Mr. Kinosian, who sat here very patiently and took this all in on behalf of Commissioner Bohn. Mr. Kinosian on behalf of Commissioner Bohn.

Thank you all for being here.

MR. LEAON: Thank you very much. I appreciate Chairman Pfannenstiel's and Commissioner Byron's participation today.

I thank our panel members for the fantastic job, thank you very much for participating in our panel discussion.

Thanks to the audience for your questions and also the KEMA team, don't want to forget you guys.

And next steps. Written comments are due October 10th. And we're tentatively scheduled for a November 20th joint IEPR/Renewables Committee meeting, consideration of the revised report. November 20th.

That concludes the workshop, and I thank you for your participation.

(Whereupon, at 4:37 p.m., the workshop was adjourned.)

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Staff Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 14th day of October, 2008.

PETER PETTY